DOCKET NO. 20170208-EI

Rhonda J. Alexander
Manager
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FILED 9/25/2017
DOCUMENT NO. 07898-2017
FPSC - COMMISSION CLERK

September 25, 2017

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

RE: Gulf Power Company's application for authority to receive common equity contributions and to issue and sell securities

Dear Ms. Stauffer:

Attached for official filing is Gulf Power Company's application for authority to receive common equity contributions and to issue and sell securities, together with exhibits certified where required. As noted in paragraph 3 of the application, the individuals authorized to receive notices and communications in respect to this application are:

Jeffrey A. Stone
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0100

Joshua J. Mason
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0761

Sincerely,

Rhonda J. Alexander

Rhonda J. Alexander
Regulatory, Forecasting and Pricing Manager

md

Attachments

Cc w/att: Gulf Power Company
Jeffrey A. Stone, Esq., General Counsel
Beggs & Lane
Russell Badders, Esq.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Gulf Power Company's application) for authority to issue and sell securities) and to receive common equity contributions))	Docket No. 17 -EI Filed: September 25, 2017

GULF POWER COMPANY'S APPLICATION FOR AUTHORITY TO ISSUE AND SELL SECURITIES AND TO RECEIVE COMMON EQUITY CONTRIBUTIONS

Gulf Power Company ("Gulf Power", "Gulf", or "the Company"), pursuant to Chapter 25-8, Florida Administrative Code, and Section 366.04, Florida Statutes, hereby files this application for authority to issue and sell securities and to receive common equity contributions during the twelve months ending December 31, 2018. In support of this application, the Company states:

(1) The exact name of the Company and the address of its principal business office is:

Physical Location	Mailing Address
Gulf Power Company	Gulf Power Company
500 Bayfront Parkway	One Energy Place
Pensacola, Florida 32520	Pensacola, FL 32520-0780

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

(3) The names and addresses of the persons authorized to receive notices and communications in respect to this application are:

Jeffrey A. Stone
Vice President, General Counsel
& Corporate Secretary
Gulf Power Company
One Energy Place
Pensacola, FL32520-0100

Joshua J. Mason
Assistant Treasurer &
Financial Planning Manager
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0761

(4) Capital Stock and Funded Debt of the Company at June 30, 2017, was:

CAPITAL STOCK

		Preference Stock $100 Par Value	Class A Preferred Stock $25 Par Value	Preferred Stock $100 Par Value	Common Stock Without Par Value
(a)	Brief description:				
(b)	Shares authorized:	10,000,000	10,000,000	10,000,000	20,000,000
(c)	Shares outstanding:	None	None	None	7,392,717
(d)	The amount held as reacquired securities:	None	None	None	None
(e)	The amount pledged by applicant:	None	None	None	None
(f)	The amount owned by affiliated corporations:	None	None	None	7,392,717
(g)	The amount held in any fund:	None	None	None	None

FUNDED DEBT

		Long-Term Notes Payable $	PCBs $
(a)	Brief description:		
(b)	Amount authorized:	Not Limited	Not Limited
(c)	Amount outstanding (000):		
	2.10% Series due 2022		37,000
	Daily Rate Series due 2022		3,930
	1.15% Series due 2023		32,550
	2.00% Series due 2037		42,000
	1.40% Series due 2039		65,000
	Daily Rate Series due 2039		65,400
	Daily Rate Series due 2042		13,000
	4.45% Series due 2044		29,075
	1.40% Series due 2049		21,000
	4.75% Sr. Notes due 2020	175,000	
	3.10% Sr. Notes due 2022	100,000	
	3.30% Sr. Notes due 2027	300,000	
	5.10% Sr. Notes due 2040	125,000	
	5.00% Sr. Notes due 2043	90,000	
	4.55% Sr. Notes due 2044	200,000	
(d)	Amount held as reacquired securities:	None	None
(e)	Amount pledged:	None	None
(f)	Amount owned by affiliated corporations:	None	None
(g)	Amount held in any fund:	None	None

(5) Statement of Proposed Transactions:

(a) The Company seeks authority to: receive equity funds from and/or issue common equity securities to Gulf's parent company, the Southern Company ("Southern"); issue and sell long-term debt and equity securities; and issue and sell short-term debt securities during the period covered by this application.

The issuance and sale of equity securities and long-term debt may be through either negotiated underwritten public offering, public offering at competitive bidding, agents or dealers, private sale, or through borrowings from lending institutions.

(i) The common equity funds from Southern may take the form of common equity contributions or the proceeds from the issuance of shares of common stock to Southern.

(ii) The other equity securities may take the form of preferred stock or preference stock (with such par values, terms and conditions, and relative rights and preferences as may be permitted by Gulf's Restated Articles of Incorporation); or options, warrants or rights with respect to the foregoing.

(iii) The long-term debt securities may take the form of first mortgage bonds, debentures, notes, guarantees, or other long-term obligations, pollution control bonds, installment contracts or other obligations securing pollution control bonds, or options, rights, interest rate swaps or other derivative instruments with respect to the foregoing with maturities ranging from one to sixty years and issued in both domestic and international markets.

The Company has established lines of credit and other credit arrangements with a group of banks and other entities under which borrowings may be made by the issuance of unsecured promissory notes. The interest rate on the proposed borrowings will bear the prevailing market interest rate at the time of issuance and may be subject

to change, either up or down. None of the promissory notes are to be resold by the banks or other entities to the public. The Company will seek to reserve the right under the lines of credit to prepay all or any portion of the loans without penalty and to reborrow the amount of any notes so prepaid.

The Company also proposes to issue short-term notes to be sold in the commercial paper market. The notes may have varying maturities not to exceed one year, which maturities may be subject to extension by the Company to a final maturity not to exceed 390 days. The notes will be sold at a discount, plus a commission to the commercial paper dealer, with the aggregate interest cost to the Company expected not to exceed the prime rate in effect at the time of the sale. The Company further proposes that such commercial paper notes may be issued for its benefit by a special purpose affiliate, which would then lend the proceeds to the Company on identical terms. Such loan would be evidenced by the Company's "grid" note issued to the affiliate.

(b) The maximum amount of common equity contributions received from and proceeds from common equity shares issued to Southern, the maximum amount of other equity securities issued and the maximum principal amount of long-term debt securities issued under the authority requested in this application will total not more than $600 million. The maximum principal amount of short-term debt outstanding at any one time under the authority requested in this application will total not more than $500 million.

The Statement of Sources and Uses of Funds and the Construction Budget for Gross Property Additions Forecast for the Year Ending December 31, 2018, is included as Exhibit B (1).

The actual capital structure at June 30, 2017, is as follows:

Component	Amount (000)	Ratio
Common Equity	$1,553,384	52.97%
Preference Stock	0	0.00%
Long-Term Debt	1,301,380	44.37%
Short-Term Debt	77,933	2.66%
TOTAL	$2,932,697	100.00%

Pretax Coverage Ratio (Excluding AFUDC): 5.27

(c) The present estimate of the dividend rate for the aforementioned equity securities and the interest rate for the aforementioned debt securities, based upon current rates for comparable securities, is as follows:

(1) The interest rate for comparable A rated 30 year Senior Notes was 3.90% as of August 31, 2017.

(2) The dividend rate for comparable BBB+ rated preference stock was 5.25% as of August 31, 2017.

(3) The prime interest rate, or its equivalent, for JPMorgan Chase Bank, N.A. was 4.00% as of August 31, 2017.

(4) The interest rate in effect for 90-day direct issue commercial paper as published in the Federal Reserve Statistical Release (Form H.15) was 1.31% as of August 31, 2017.

(d) The actual dividend rate and actual interest rates will be determined by market conditions at the time of the sale of the securities.

(6) Purpose of Issues:

The net proceeds to be received from these additional funds will be added to the Company's general funds and will be used for working capital requirements and for

other general business purposes, including the financing of the Company's construction program.

(a) The Company is engaged in a continuous construction program to accommodate existing and estimated future loads of the system. Total construction additions during 2018 are estimated to cost $212,872,000 and are expected to be apportioned as shown in Exhibit B (1).

At present, none of the planned expenditures require certification of need by this Commission under the Florida Electrical Power Plant Siting Act or the Transmission Line Siting Act. The Company's long-range construction program is subject to periodic review and revision. The construction program referred to herein has been necessitated by continued growth in the demand for service on the Company's system and the replacement and improvements required to our existing system. It is manifestly in the public interest for the Company to raise the funds which are required to perform such service.

(b) Included among the purposes of the security issues could be the reimbursement of the treasury for expenditures against which securities have not been issued.

(c) The net proceeds received may also be used to repay previously issued short-term unsecured promissory notes and to refund previously issued long-term debt. Subject to market conditions, the Company may refund such long-term obligations with new issuances of long-term debt, preferred stock, and/or preference stock.

(7) The Company submits that the proposed additional funds are for lawful objects within the corporate purposes of the Company and compatible with the public interest and are reasonably necessary or appropriate for such purposes. The facts relied upon by the Company in support of such allegations are set forth in paragraph (6) hereof.

(8) The name and address of counsel who will pass upon the legality of the proposed issues are:

Jeffrey A. Stone
Vice President, General Counsel
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0100

Troutman Sanders LLP
600 Peachtree Street
Suite 5200
Atlanta, GA 30308-2216

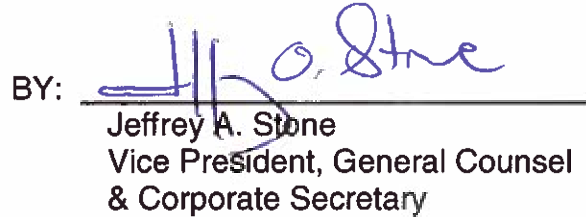
(9) A Registration Statement with respect to each public offering of securities hereunder that is subject to and not exempt from the registration requirements of the Securities Act of 1933, as amended, will be filed with the Securities and Exchange Commission, 100 F St. N.E., Washington, D.C. 20549.

(10) Southern, a Delaware corporation, owns 7,392,717 shares of the Company's common stock, without par value, representing 100% of the voting stock outstanding. Southern is also the parent company of three other traditional electric operating companies and certain other companies including: Southern LINC Wireless; Southern Company Services; Southern Nuclear; Southern Holdings; Southern Company Gas; PowerSecure International, Inc.; and other direct and indirect subsidiaries.

WHEREFORE, the Company respectfully requests an order authorizing it to issue and sell securities and to receive common equity contributions from Southern during the twelve months ending December 31, 2018.

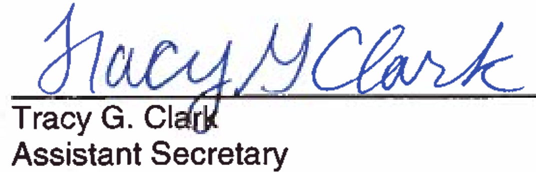
DATED: September 25, 2017

GULF POWER COMPANY

BY: 

Jeffrey A. Stone
Vice President, General Counsel
& Corporate Secretary

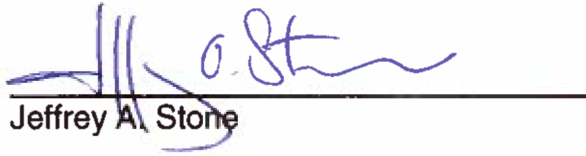
ATTEST:



Tracy G. Clark
Assistant Secretary

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Jeffrey A. Stone, being duly sworn, deposes and says that he is the Vice President, General Counsel and Corporate Secretary of Gulf Power Company, that he has read the foregoing petition and knows the contents thereof, and that the facts therein are true and correct to the best of his knowledge, information and belief.



Jeffrey A. Stone

STATE OF FLORIDA
COUNTY OF ESCAMBIA

The foregoing instrument was acknowledged before me this 25th day of September, 2017, by Jeffrey A. Stone of Gulf Power Company, a Florida corporation, on behalf of the corporation. He is personally known to me and did take an oath.

NOTARY PUBLIC

REQUIRED EXHIBITS

Exhibit A (6)(i) -	The financial statements and accompanying footnotes as they appear in the Company's Annual Report on Form 10-K for the year ended December 31, 2016, and filed with the SEC in file no. 1-31737 on February 22, 2017.
Exhibit A (6)(ii) -	The financial statements and accompanying footnotes as they appear in the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017, and filed with the SEC in file no. 1-31737 on August 2, 2017.
Exhibit B (1) -	Statement of Sources and Uses of Funds for the twelve months ended December 31, 2018 and the Construction Budget for Gross Property Additions.

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

FORM 10-K

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

For the Fiscal Year Ended December 31, 2016

OR

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

For the Transition Period from to

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-3526	**The Southern Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-0690070
1-3164	**Alabama Power Company** (An Alabama Corporation) 600 North 18th Street Birmingham, Alabama 35291 (205) 257-1000	63-0004250
1-6468	**Georgia Power Company** (A Georgia Corporation) 241 Ralph McGill Boulevard, N.E. Atlanta, Georgia 30308 (404) 506-6526	58-0257110
001-31737	**Gulf Power Company** (A Florida Corporation) One Energy Place Pensacola, Florida 32520 (850) 444-6111	59-0276810
001-11229	**Mississippi Power Company** (A Mississippi Corporation) 2992 West Beach Boulevard Gulfport, Mississippi 39501 (228) 864-1211	64-0205820
001-37803	**Southern Power Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-2598670
1-14174	**Southern Company Gas** (A Georgia Corporation) Ten Peachtree Place, N.E. Atlanta, Georgia 30309	58-2210952

(404) 584-4000

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

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

Title of each class	Registrant
Common Stock, $5 par value	**The Southern Company**
Junior Subordinated Notes, $25 denominations	
6.25% Series 2015A due 2075	
5.25% Series 2016A due 2076	
Class A preferred stock, cumulative, $25 stated capital	**Alabama Power Company**
5.83% Series	
Class A preferred stock, non-cumulative, Par value $25 per share	**Georgia Power Company**
6 1/8% Series	
Depositary preferred shares, each representing one-fourth of a share of preferred stock, cumulative, $100 par value	**Mississippi Power Company**
5.25% Series	
Senior Notes	**Southern Power Company**
1.000% Series 2016A due 2022	
1.850% Series 2016B due 2026	

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

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

1 As of December 31, 2016.

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

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

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

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

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

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

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

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

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

Aggregate market value of The Southern Company's common stock held by non-affiliates of The Southern Company at June 30, 2016: $51.1 billion. All of the common stock of the other registrants is held by The Southern Company. A description of each registrant's common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at January 31, 2017
The Southern Company	Par Value $5 Per Share	991,051,161
Alabama Power Company	Par Value $40 Per Share	30,537,500
Georgia Power Company	Without Par Value	9,261,500
Gulf Power Company	Without Par Value	7,392,717
Mississippi Power Company	Without Par Value	1,121,000
Southern Power Company	Par Value $0.01 Per Share	1,000
Southern Company Gas	Par Value $0.01 Per Share	100

Documents incorporated by reference: specified portions of The Southern Company's Definitive Proxy Statement on Schedule 14A relating to the 2017 Annual Meeting of Stockholders are incorporated by reference into PART III. In addition, specified portions of the Definitive Information Statements on Schedule 14C of Alabama Power Company, Georgia Power Company, and Mississippi Power Company relating to each of their respective 2017 Annual Meetings of Shareholders are incorporated by reference into PART III.

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

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

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DEFINITIONS

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

Term	Meaning
Alabama Power	Alabama Power Company
Bcf	Billion cubic feet
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
Contractor	Westinghouse and its affiliate, WECTEC Global Project Services Inc. (formerly known as CB&I Stone & Webster, Inc.), formerly a subsidiary of The Shaw Group Inc. and Chicago Bridge & Iron Company N.V.
Dalton	City of Dalton, Georgia, acting by and through its Board of Water, Light, and Sinking Fund Commissioners
DOE	U.S. Department of Energy
Duke Energy Florida	Duke Energy Florida, LLC
EMC	Electric membership corporation
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FMPA	Florida Municipal Power Agency
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IBEW	International Brotherhood of Electrical Workers
IGCC	Integrated coal gasification combined cycle
IIC	Intercompany Interchange Contract
Internal Revenue Code	Internal Revenue Code of 1986, as amended
IPP	Independent Power Producer
IRP	Integrated Resource Plan
Kemper IGCC	IGCC facility under construction by Mississippi Power in Kemper County, Mississippi
KUA	Kissimmee Utility Authority
KW	Kilowatt
KWH	Kilowatt-hour
MEAG Power	Municipal Electric Authority of Georgia
Merger	The merger, effective July 1, 2016, of a wholly-owned, direct subsidiary of Southern Company with and into Southern Company Gas, with Southern Company Gas continuing as the surviving corporation
Mississippi Power	Mississippi Power Company
MW	Megawatt
natural gas distribution utilities	Southern Company Gas' seven natural gas distribution utilities (Nicor Gas, Atlanta Gas Light Company, Virginia Natural Gas, Inc., Elizabethtown Gas, Florida City Gas, Chattanooga Gas Company, and Elkton Gas)
Nicor Gas	Northern Illinois Gas Company, a wholly-owned subsidiary of Southern Company Gas
NRC	U.S. Nuclear Regulatory Commission
NYSE	New York Stock Exchange
OPC	Oglethorpe Power Corporation
OUC	Orlando Utilities Commission
PATH Act	Protecting Americans from Tax Hikes Act
Plant Vogtle Units 3 and 4	Two new nuclear generating units under construction at Georgia Power's Plant Vogtle

DEFINITIONS
(continued)

Term	**Meaning**
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
PowerSecure	PowerSecure Inc.
PowerSouth	PowerSouth Energy Cooperative
PPA	Power purchase agreements and contracts for differences that provide the owner of a renewable facility a certain fixed price for the electricity sold to the grid
PSC	Public Service Commission
registrants	Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and Southern Company Gas
RUS	Rural Utilities Service
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
SEPA	Southeastern Power Administration
SERC	Southeastern Electric Reliability Council
SMEPA	South Mississippi Electric Power Association (now known as Cooperative Energy)
Southern Company	The Southern Company
Southern Company Gas	Southern Company Gas (formerly known as AGL Resources Inc.) and its subsidiaries
Southern Company Gas Capital	Southern Company Gas Capital Corporation (formerly known as AGL Capital Corporation), a 100%-owned subsidiary of Southern Company Gas
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 (as of May 9, 2016), and other subsidiaries
Southern Holdings	Southern Company Holdings, Inc.
Southern LINC	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional electric operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power
Vogtle Owners	Georgia Power, OPC, MEAG Power, and Dalton
Westinghouse	Westinghouse Electric Company LLC

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K contains forward-looking statements. Forward-looking statements include, among other things, statements concerning regulated rates, the strategic goals for the wholesale business, 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 s, postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, completion dates of construction projects, filings with state and federal regulatory authorities, impact of the PATH Act, federal income tax benefits, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws regulating emissions, discharges, and disposal to air, water, and land , and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, including potential tax reform legislation, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries ;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity and natural gas, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of natural gas and other fuels;
- limits on pipeline capacity;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development , construction, and operation of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor , sustaining nitrogen supply, contractor or supplier delay, non-performance under construction, operating, or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by any PSC);
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any environmental performance standards and the requirements of tax credits and other incentives , and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of the Southern Company system's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- ongoing renewable energy partnerships and development agreements;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions;
- actions related to cost recovery for the Kemper IGCC, including the ultimate impact of the 2015 decision of the Mississippi Supreme Court, the Mississippi PSC's December 2015 rate order, and related legal or regulatory proceedings, Mississippi

PSC review of the prudence of Kemper IGCC costs and approval of further permanent rate recovery plans, actions relating to proposed securitization, satisfaction of requirements to utilize grants, and the ultimate impact of the termination of the proposed sale of an interest in the Kemper IGCC to SMEPA;

- the ability to successfully operate the electric utilities' generating, transmission, and distribution facilities and Southern Company Gas' natural gas distribution and storage facilities and the successful performance of necessary corporate functions;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- the inherent risks involved in transporting and storing natural gas;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the possibility that the anticipated benefits from the Merger cannot be fully realized or may take longer to realize than expected, the possibility that costs related to the integration of Southern Company and Southern Company Gas will be greater than expected, the ability to retain and hire key personnel and maintain relationships with customers, suppliers, or other business partners, and the diversion of management time on integration-related issues;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Southern Company system's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in Southern Company's and any of its subsidiaries' credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general , as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of Southern Company's electric utilities 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 Southern Company system's business resulting from incidents affecting the U.S. electric grid , natural gas pipeline infrastructure , or operation of generating or storage resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the registrants from time to time with the SEC.

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

PART I

Item 1. BUSINESS

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

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

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

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

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

In addition, Southern Company owns all of the common stock of Southern Power Company, which is also an operating public utility company. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Power Company is a corporation organized under the laws of Delaware on January 8, 2001. The term "Southern Power" when used herein refers to Southern Power Company and its subsidiaries while the term "Southern Power Company" when used herein refers only to the parent company.

On July 1, 2016, Southern Company completed the Merger for a total purchase price of approximately $8.0 billion and Southern Company Gas became a wholly-owned, direct subsidiary of Southern Company. Southern Company Gas is an energy services holding company whose primary business is the distribution of natural gas in seven states - Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee, and Maryland - through the natural gas distribution utilities. Southern Company Gas is also involved in several other businesses that are complementary to the distribution of natural gas. Southern Company Gas was incorporated under the laws of the State of Georgia on November 27, 1995 for the primary purpose of becoming the holding company for Atlanta Gas Light Company, which was founded in 1856.

Southern Company also owns all of the outstanding common stock or membership interests of SCS, Southern LINC, Southern Holdings, Southern Nuclear, PowerSecure, and other direct and indirect subsidiaries. SCS, the system service company, has contracted with Southern Company, each traditional electric operating company, Southern Power, Southern Company Gas, Southern Nuclear, SEGCO, and other subsidiaries to furnish, at direct or allocated cost and upon request, the following services: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communication, and other services with respect to business and operations, construction management, and power pool transactions. Southern LINC provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and for other electric services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants and is currently developing Plant Vogtle Units 3 and 4, which are co-owned by Georgia Power. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.

Alabama Power and Georgia Power each own 50% of the outstanding common stock of SEGCO. SEGCO is an operating public utility company that owns electric generating units with an aggregate capacity of 1,020 MWs at Plant Gaston on the Coosa River near Wilsonville, Alabama. Alabama Power and Georgia Power are each entitled to one-half of SEGCO's capacity and energy. Alabama Power acts as SEGCO's agent in the operation of SEGCO's units and furnishes fuel to SEGCO for its units. SEGCO also owns one 230,000 volt transmission line extending from Plant Gaston to the Georgia state line at which

point connection is made with the Georgia Power transmission line system. SEGCO added natural gas as a fuel source for 1,000 MWs of its generating capacity in 2015. In April 2016, natural gas became the primary fuel source. Alabama Power, which owns and operates a generating unit adjacent to the SEGCO generating units, has entered into a joint ownership agreement with SEGCO for the ownership of an associated gas pipeline. Alabama Power owns 14% of the pipeline with the remaining 86% owned by SEGCO.

Southern Company's segment information is included in Note 13 to the financial statements of Southern Company in Item 8 herein. Southern Company Gas' segment information is included in Note 12 to the financial statements of Southern Company Gas in Item 8 herein.

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

The Southern Company System

Traditional Electric Operating Companies

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

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

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

Southern Power and Southern LINC have secured from the traditional electric operating companies certain services which are furnished at cost in compliance with FERC regulations.

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

Southern Power

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

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

Some of SRP's partnerships allow for the sharing of cash distributions and tax benefits at differing percentages. SRP is entitled to 51% of all cash distributions from eight of the partnership entities and the respective partner who holds the class B membership interests is entitled to 49% of all cash distributions. For the Desert Stateline partnership, SRP is entitled to 66% of all cash distributions and the class B member is entitled to 34% of all cash distributions. In addition, Southern Power is entitled to substantially all of the federal tax benefits with respect to these nine partnership entities.

During 2016, Southern Power acquired or commenced construction of approximately 2,134 MWs of additional solar, wind, and natural gas facilities and completed construction of approximately 1,060 MWs of solar facilities. The aggregate purchase price for projects acquired by Southern Power's subsidiaries during 2016 and 2015 was $2.3 billion and $1.4 billion, respectively. During 2016, Southern Power's subsidiaries completed construction of and placed in service projects with a total construction cost of approximately $3.2 billion.

In December 2016, as part of Southern Power's renewable development strategy, SRP entered into a joint development agreement with Renewable Energy Systems Americas, Inc. (RES) to develop and construct approximately 3,000 MWs across 10 wind projects expected to be placed in service between 2018 and 2020. Also in December 2016, Southern Power signed agreements and made payments to purchase wind turbine equipment from Siemens Wind Projects, Inc. and Vestas-American Wind Technology, Inc. to be used for construction of the facilities. Once these wind projects reach commercial operation, they are expected to qualify for 100% production tax credits (PTCs).

The ultimate outcome of these matters cannot be determined at this time. For additional information on SRE and SRP, see MANAGEMENT'S DISCUSSION AND ANALYSIS – "Acquisitions" and "Construction Projects" of Southern Power in Item 7 herein.

See Item 2 – Properties, Note 2 to the financial statements of Southern Power in Item 8 herein, and Note 12 to the financial statements of Southern Company under "Southern Power" in Item 8 herein for additional information regarding Southern Power's acquisitions, construction, and development projects.

As of December 31, 2016, Southern Power owned generating units totaling 11,768 MWs of nameplate capacity in commercial operation, after taking into consideration its equity ownership percentage of the solar and wind facilities. Southern Power calculates an investment coverage ratio for its generating assets based on the ratio of investment under contract to total investment using the respective generation facilities' net book value (or expected in-service value for facilities under construction or being acquired) as the investment amount. With the inclusion of the PPAs and investment associated with the solar and natural-gas fired facilities currently under construction and Bethel Wind, which was acquired subsequent to December 31, 2016, as well as other capacity and energy contracts, Southern Power has an average investment coverage ratio of 91% through 2021 and 90% through 2026, with an average remaining contract duration of approximately 16 years.

Southern Power's natural gas and biomass sales are primarily through long-term PPAs that consist of two types of agreements. The first type, referred to as a unit or block sale, is a customer purchase from a dedicated plant unit where all or a portion of the generation from that unit is reserved for that customer. Southern Power typically has the ability to serve the unit or block

sale customer from an alternate resource. The second type, referred to as requirements service, provides that Southern Power serve the customer's capacity and energy requirements from a combination of the customer's own generating units and from Southern Power resources not dedicated to serve unit or block sales. Southern Power has rights to purchase power provided by the requirements customers' resources when economically viable.

Southern Power's electricity sales from solar and wind generating facilities are predominantly through long-term PPAs; however, these solar and wind PPAs do not have a capacity charge and customers either purchase the energy output of a dedicated renewable facility through an energy charge or provide Southern Power a certain fixed price for the electricity sold to the grid.

The following tables set forth Southern Power's PPAs as of December 31, 2016:

Block Sales PPAs

Facility/Source	**Counterparty**	**MWs**	**Contract Term**
Addison Unit 1	MEAG Power	152	through April 2029
Addison Units 2 and 4	Georgia Power	293	through May 2030
Addison Unit 3	Georgia Energy Cooperative	151	through May 2030
Cleveland County Unit 1	North Carolina Electric Membership Corporation (NCEMC)	45-180	through Dec. 2036
Cleveland County Unit 2	NCEMC	180	through Dec. 2036
Cleveland County Unit 3	North Carolina Municipal Power Agency 1	183	through Dec. 2031
Dahlberg Units 1, 3, and 5	Cobb EMC	224	through Dec. 2026
Dahlberg Units 2, 6, 8, and 10	Georgia Power	298	through May 2025
Dahlberg Unit 4	Georgia Power	73	through May 2030
Franklin Unit 1	Duke Energy Florida	434	through May 2021
Franklin Unit 2	Morgan Stanley Capital Group	250	through Dec. 2025
Franklin Unit 2	Jackson EMC	60-65	through Dec. 2035
Franklin Unit 2	GreyStone Power Corporation	35-40	through Dec. 2035
Franklin Unit 2	Cobb EMC	100	through Dec. 2026
Franklin Unit 3	Morgan Stanley Capital Group	200	through Dec. 2027
Harris Unit 1	Georgia Power	628	through May 2030
Harris Unit 2	Georgia Power	649	through May 2019
Harris Unit 2	Alabama Municipal Electric Authority(1)	25	Jan. 2020 – Dec. 2025
Mankato	Northern States Power Company	375	through June 2026
Mankato	Northern States Power Company	345	June 2019 – May 2039(2)
Nacogdoches	City of Austin, Texas	100	through May 2032
NCEMC PPA(3)	EnergyUnited	100	through Dec. 2021
Oleander Units 2, 3, and 4	Seminole Electric Cooperative	465	through May 2021
Oleander Unit 5	FMPA	157	through Dec. 2027
Rowan CT Unit 1	North Carolina Municipal Power Agency 1	150	through Dec. 2030
Rowan CT Units 2 and 3	EnergyUnited	100-175	Jan. 2022 – Dec. 2025
Rowan CT Unit 3	EnergyUnited	113	through Dec. 2023
Rowan CC Unit 4	EnergyUnited	9-328	through Dec. 2025
Rowan CC Unit 4	Duke Energy Progress, LLC	150	through Dec. 2019
Rowan CC Unit 4(4)	Century Aluminum	154	through Dec. 2017
Stanton Unit A	OUC	341	through Sept. 2033
Stanton Unit A	FMPA	85	through Sept. 2033
Wansley Unit 6	Georgia Power	570	through May 2017

(1) Alabama Municipal Electric Authority will also be served by Plant Franklin Unit 1 from January 2018 through December 2019.
(2) Subject to commercial operation of the expansion project.
(3) Represents sale of power purchased from NCEMC under a PPA.
(4) Century Aluminum PPA is partially served by Plant Franklin Unit 3.

Requirements Services PPAs

Counterparty	MWs		Contract Term
Nine Georgia EMCs	281-370	(1)	through Dec. 2024
Sawnee EMC	267-609	(1)	through Dec. 2027
Cobb EMC	0-160	(1)	through Dec. 2026
Flint EMC	132-316	(1)	through Dec. 2024
City of Dalton, Georgia	60		through Dec. 2017
EnergyUnited	55-152	(1)	through Dec. 2025
City of Blountstown, Florida	10		through April 2022

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

Solar/Wind PPAs

Facility	Counterparty	MWs(1)	Contract Term
Solar			
Adobe(2)	Southern California Edison Company	20	through May 2034
Apex(2)	Nevada Power Company	20	through Dec. 2037
Boulder 1(3)	Nevada Power Company	100	through Dec. 2036
Butler	Georgia Power	100	through Dec. 2046
Butler Solar Farm	Georgia Power	20	through Feb. 2036
Calipatria(2)	San Diego Gas & Electric Company	20	through Feb. 2036
Campo Verde(2)	San Diego Gas & Electric Company	139	through Sept. 2033
Cimarron(2)	Tri-State Generation and Transmission Association, Inc.	30	through Nov. 2035
Decatur County	Georgia Power	19	through Dec. 2035
Decatur Parkway	Georgia Power	80	through Dec. 2040
Desert Stateline(4)	Southern California Edison Company	300	through Aug. 2036
East Pecos	Austin Energy	119	March 2017 – Feb. 2032 (6)
Garland A(3)	Southern California Edison Company	20	through Sept. 2036
Garland(3)	Southern California Edison Company	180	through Oct. 2031
Granville(2)	Duke Energy Progress, LLC	2	through Nov. 2032
Henrietta(3)	Pacific Gas & Electric Company	100	through Sept. 2036
Imperial Valley(3)	San Diego Gas & Electric Company	150	through Nov. 2039
Lamesa	City of Garland, Texas	102	April 2017 – March 2032 (6)
Lost Hills Blackwell(3)	City of Roseville & Pacific Gas & Electric Company	32	through Dec. 2043
Macho Springs(2)	El Paso Energy	50	through May 2034
Morelos(2)	Pacific Gas & Electric Company	15	through Feb. 2036
North Star(3)	Pacific Gas & Electric Company	60	through June 2035
Pawpaw	Georgia Power	30	through March 2046
Roserock(3)	Austin Energy	157	through Nov. 2036
Rutherford(2)	Duke Energy Carolinas, LLC	75	through Dec. 2031

Facility	Counterparty	MWs(1)	Contract Term
Sandhills	Cobb EMC	111	through Oct. 2041
Sandhills	Flint EMC	15	through Oct. 2041
Sandhills	Sawnee EMC	15	through Oct. 2041
Sandhills	Middle Georgia and Irwin EMC	2	through Oct. 2041
Spectrum(2)	Nevada Power Company	30	through Dec. 2038
Tranquillity(3)	Shell Energy North America (US), LP	204	through Nov. 2019
Tranquillity(3)	Southern California Edison Company	204	Dec. 2019 – Nov. 2034
Wind			
Grant Plains	Oklahoma Municipal Power Authority	41	Jan. 2020 – Dec. 2039
Grant Plains	Steelcase Inc.	25	through Dec. 2028
Grant Plains	Allianz Risk Transfer (Bermuda) Ltd.	81-122	April 2017 – March 2027
Grant Wind	East Texas Electric Cooperative	50	through March 2036
Grant Wind	Northeast Texas Electric Cooperative	50	through March 2036
Grant Wind	Western Farmers Electric Cooperative	50	through March 2036
Kay Wind	Westar Energy Inc.	199	through Sept. 2036
Kay Wind	Grand River Dam Authority	100	through Dec. 2035
Passadumkeag	Western Massachusetts Electric Company	40	through June 2031
Salt Fork Wind	City of Garland, Texas	150	through Nov. 2030
Salt Fork Wind	Salesforce.com, Inc.	24	through Nov. 2028
Tyler Bluff Wind	The Proctor & Gamble Company	96	through Dec. 2028
Wake Wind(5)	Equinix Enterprises, Inc.	100	through Oct. 2028
Wake Wind(5)	Owens Corning	125	through Oct. 2028

(1) MWs shown are for 100% of the PPA, which is based on demonstrated capacity of the facility.
(2) Southern Power's subsidiary's equity interest in these facilities is 90%.
(3) Southern Power's subsidiary's equity interest in these facilities is 51%.
(4) Southern Power's subsidiary's equity interest in this facility is 66%.
(5) Southern Power's subsidiary's equity interest in this facility is 90.1%.
(6) Subject to commercial operation.

Purchased Power

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

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

For the year ended December 31, 2016, Southern Power's revenues were derived approximately 16.5% from Georgia Power. Southern Power actively pursues replacement PPAs prior to the expiration of its current PPAs and anticipates that the revenues attributable to one customer may be replaced by revenues from a new customer; however, the expiration of any of Southern Power's current PPAs without the successful remarketing of a replacement PPA could have a material negative impact on Southern Power's earnings but is not expected to have a material impact on Southern Company's earnings.

Southern Company Gas

Southern Company Gas is an energy services holding company whose primary business is the distribution of natural gas through the natural gas distribution utilities. Southern Company Gas is also involved in several other businesses that are complementary to the distribution of natural gas, including gas marketing services, wholesale gas services, and gas midstream operations.

Gas distribution operations, the largest segment of Southern Company Gas' business, operates, constructs, and maintains 81,600 miles of natural gas pipelines and 14 storage facilities, with total capacity of 158 Bcf, to provide natural gas to residential, commercial, and industrial customers. Gas distribution operations serves approximately 4.6 million customers across seven states and has rates of return that are regulated by each individual state in return for exclusive franchises.

Gas marketing services is comprised of Southstar Energy Services, LLC (SouthStar) and Nicor Energy Services Company (doing business as Pivotal Home Solutions) and provides natural gas commodity and related services to customers in competitive markets or markets that provide for customer choice. SouthStar, serving approximately 643,000 natural gas commodity customers, markets gas to residential, commercial, and industrial customers and offers energy-related products that provide natural gas price stability and utility bill management. Pivotal Home Solutions, serving approximately 1.2 million service contracts, provides a suite of home protection products and services that offers homeowners predictability regarding their energy service delivery, systems, and appliances.

Wholesale gas services consists of Sequent Energy Management, L.P. and engages in natural gas storage and gas pipeline arbitrage and provides natural gas asset management and related logistical services to most of the natural gas distribution utilities as well as non-affiliate companies.

Gas midstream operations includes joint ventures in pipeline investments (including a 50% ownership interest in SNG and two significant pipeline construction projects) as well as a 50% joint ownership in a significant pipeline project and wholly-owned natural gas storage facilities that enable the provision of diverse sources of natural gas supplies to the customers of Southern Company Gas. On September 1, 2016, Southern Company Gas paid $1.4 billion to acquire a 50% equity interest in SNG, which is the owner of a 7,000 mile pipeline connecting natural gas supply basins in Texas, Louisiana, Mississippi, and Alabama to markets in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina, and Tennessee.

For additional information on Southern Company Gas' business activities, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Business Activities" and – FUTURE EARNINGS POTENTIAL of Southern Company Gas in Item 7 herein.

Other Businesses

PowerSecure provides products and services in the areas of distributed generation, energy efficiency, and utility infrastructure. Southern Company acquired PowerSecure on May 9, 2016 for an aggregate purchase price of $429 million.

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

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

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

Construction Programs

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. For estimated construction and environmental expenditures for the periods 2017 through 2021, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company, each traditional electric operating company, Southern Power, and Southern Company Gas in Item 7 herein. The Southern Company system's construction program consists of capital investment and capital expenditures to comply with environmental statutes and regulations. The traditional electric operating companies also anticipate costs associated with closure and groundwater monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are reflected in the Southern Company system's asset retirement obligation liabilities. In 2017, the construction program is expected to be apportioned approximately as follows:

	Southern Company system [a][b]	Alabama Power	Georgia Power	Gulf Power	Mississippi Power
			(in billions)		
New Generation	$ 1.0	$ —	$ 0.7	$ —	$ 0.3
Environmental Compliance [c]	0.9	0.5	0.4	—	—
Generation Maintenance	0.9	0.4	0.3	0.1	0.1
Transmission	0.8	0.3	0.4	—	—
Distribution	1.0	0.4	0.5	0.1	0.1
Nuclear Fuel	0.2	0.1	0.1	—	—
General Plant	0.4	0.1	0.2	—	0.1
	5.3	1.9	2.6	0.2	0.5
Southern Power [d]	1.6				
Southern Company Gas [e]	1.7				
Other subsidiaries	0.5				
Total [a]	$ 9.1	$ 1.9	$ 2.6	$ 0.2	$ 0.5

(a) Totals do not add due to rounding.

(b) Includes the traditional electric operating companies, Southern Power, and Southern Company Gas, as well as the other subsidiaries. See "Other Businesses" herein for additional information.

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

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

(e) Includes costs for ongoing capital projects associated with infrastructure improvement programs in six different states that have been previously approved by their applicable state regulatory agencies. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Infrastructure Replacement Programs and Capital Projects" of Southern Company Gas in Item 7 herein for additional information.

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in electric generating plants, including unit retirements and replacements and adding or changing fuel sources at existing electric generating units, to meet regulatory requirements; changes in FERC rules and regulations; state regulatory agency approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. Additionally, planned expenditures for plant acquisitions may vary due to market opportunities and Southern Power's ability to execute its growth strategy.

In addition, the construction program includes the development and construction of new electric generating facilities with designs that have not been finalized or previously constructed, including first-of-a-kind technology, which may result in revised estimates during construction. See Note 3 to the financial statements of Southern Company and Georgia Power under "Regulatory Matters – Georgia Power – Nuclear Construction" and "Retail Regulatory Matters – Nuclear Construction," respectively, in Item 8 herein for additional information regarding Georgia Power's construction of Plant Vogtle Units 3 and 4. Also see Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 herein for additional information regarding Mississippi Power's construction of the Kemper IGCC.

Also see "Regulation – Environmental Statutes and Regulations" herein for additional information with respect to certain existing and proposed environmental requirements and PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information concerning Alabama Power's, Georgia Power's, and Southern Power's joint ownership of certain generating units and related facilities with certain non-affiliated utilities.

Financing Programs

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

Fuel Supply

Electric

The traditional electric operating companies' and SEGCO's supply of electricity is primarily fueled by natural gas and coal. Southern Power's supply of electricity is primarily fueled by natural gas. See MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – "Electricity Business – Fuel and Purchased Power Expenses" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – "Fuel and Purchased Power Expenses" of each traditional electric operating company in Item 7 herein for information regarding the electricity generated and the average cost of fuel in cents per net KWH generated for the years 2014 through 2016.

The traditional electric operating companies have agreements in place from which they expect to receive substantially all of their coal burn requirements in 2017. These agreements have terms ranging between one and four years. In 2016, the weighted average sulfur content of all coal burned by the traditional electric operating companies was 0.98% sulfur. This sulfur level, along with banked and purchased sulfur dioxide allowances, allowed the traditional electric operating companies to remain within limits set by Phase I of the Cross-State Air Pollution Rule (CSAPR) under the Clean Air Act. In 2016, the Southern Company system did not purchase any sulfur dioxide allowances, annual nitrogen oxide emission allowances, or seasonal nitrogen oxide emission allowances from the market. As any additional environmental regulations are proposed that impact the utilization of coal, the traditional electric operating companies' fuel mix will be monitored to help ensure that the traditional electric operating companies remain in compliance with applicable laws and regulations. Additionally, Southern Company and the traditional electric operating companies will continue to evaluate the need to purchase additional emissions allowances, the timing of capital expenditures for emissions control equipment, and potential unit retirements and replacements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company, each traditional electric operating company, and Southern Power in Item 7 herein for additional information on environmental matters.

SCS, acting on behalf of the traditional electric operating companies and Southern Power Company, has agreements in place for the natural gas burn requirements of the Southern Company system. For 2017, SCS has contracted for 477 Bcf of natural gas supply under agreements with remaining terms up to 15 years. In addition to natural gas supply, SCS has contracts in place for both firm natural gas transportation and storage. Management believes these contracts provide sufficient natural gas supplies, transportation, and storage to ensure normal operations of the Southern Company system's natural gas generating units.

Alabama Power and Georgia Power have multiple contracts covering their nuclear fuel needs for uranium, conversion services, enrichment services, and fuel fabrication. The uranium, conversion services, and fuel fabrication contracts are for terms of less than 10 years with varying expiration dates. The term lengths for the enrichment services contracts are for less than 15 years with varying expiration dates. Management believes suppliers have sufficient nuclear fuel production capability to permit the normal operation of the Southern Company system's nuclear generating units.

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

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

Natural Gas

Recent advances in natural gas drilling in shale producing regions of the U.S. have resulted in historically high supplies of natural gas and relatively low prices for natural gas. Procurement plans for natural gas supply and transportation to serve regulated utility customers are reviewed and approved by the state regulatory agencies in which Southern Company Gas operates. Southern Company Gas purchases natural gas supplies in the open market by contracting with producers and marketers and from its wholly-owned subsidiary, Sequent Energy Management, L.P., under asset management agreements in

states where such agreements are approved by the applicable state regulatory agency. Southern Company Gas also contracts for transportation and storage services from interstate pipelines that are regulated by the FERC. When firm pipeline services are temporarily not needed, Southern Company Gas may release the services in the secondary market under FERC-approved capacity release provisions or utilize asset management arrangements, thereby reducing the net cost of natural gas charged to customers for most of the natural gas distribution utilities. Peak-use requirements are met through utilization of company-owned storage facilities, pipeline transportation capacity, purchased storage services, peaking facilities, and other supply sources, arranged by either transportation customers or Southern Company Gas.

Territory Served by the Southern Company System

Traditional Electric Operating Companies and Southern Power

The territory in which the traditional electric operating companies provide electric service comprises most of the states of Alabama and Georgia, together with the northwestern portion of Florida and southeastern Mississippi. In this territory there are non-affiliated electric distribution systems that obtain some or all of their power requirements either directly or indirectly from the traditional electric operating companies. As of December 31, 2016, the territory had an area of approximately 120,000 square miles and an estimated population of approximately 17 million. Southern Power sells electricity at market-based rates in the wholesale market, primarily to investor-owned utilities, IPPs, municipalities, electric cooperatives, and other load serving entities.

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

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

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

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

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

The RUS has authority to make loans to cooperative associations or corporations to enable them to provide electric service to customers in rural sections of the country. As of December 31, 2016, there were 71 electric cooperative organizations operating in the territory in which the traditional electric operating companies provide electric service at retail or wholesale.

One of these organizations, PowerSouth, is a generating and transmitting cooperative selling power to several distributing cooperatives, municipal systems, and other customers in south Alabama and northwest Florida. As of December 31, 2016, PowerSouth owned generating units with approximately 2,100 MWs of nameplate capacity, including an undivided 8.16% ownership interest in Alabama Power's Plant Miller Units 1 and 2. PowerSouth's facilities were financed with RUS loans secured by long-term contracts requiring distributing cooperatives to take their requirements from PowerSouth to the extent such energy is available. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for details of Alabama Power's joint-ownership with PowerSouth of a portion of Plant Miller. Alabama Power has a 15-year system supply agreement with PowerSouth to provide 200 MWs of capacity service with an option to extend and renegotiate in the event Alabama Power builds new generation or contracts for new capacity.

Alabama Power and Gulf Power have entered into separate agreements with PowerSouth involving interconnection between their respective systems. The delivery of capacity and energy from PowerSouth to certain distributing cooperatives in the

service territories of Alabama Power and Gulf Power is governed by the Southern Company/PowerSouth Network Transmission Service Agreement. The rates for this service to PowerSouth are on file with the FERC.

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

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

As of December 31, 2016, there were approximately 65 municipally-owned electric distribution systems operating in the territory in which the traditional electric operating companies provide electric service at retail or wholesale.

As of December 31, 2016, 48 municipally-owned electric distribution systems and one county-owned system received their requirements through MEAG Power, which was established by a Georgia state statute in 1975. MEAG Power serves these requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, and purchases from other resources. MEAG Power also has a pseudo scheduling and services agreement with Georgia Power. Dalton serves its requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, and through purchases from Georgia Power and Southern Power through a service agreement. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

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

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

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

Southern Company Gas

Southern Company Gas is engaged in the distribution of natural gas in seven states through the natural gas distribution utilities. The natural gas distribution utilities construct, manage, and maintain intrastate natural gas pipelines and distribution facilities and include:

Utility	State	Number of customers (in thousands)	Approximate miles of pipe
Nicor Gas	Illinois	2,220	34,300
Atlanta Gas Light Company	Georgia	1,603	33,100
Virginia Natural Gas, Inc.	Virginia	296	5,600
Elizabethtown Gas	New Jersey	287	3,200
Florida City Gas	Florida	108	3,700
Chattanooga Gas Company	Tennessee	65	1,600
Elkton Gas	Maryland	7	100
Total		4,586	81,600

For information relating to the sources of revenue for Southern Company Gas, see MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATIONS and – FUTURE EARNINGS POTENTIAL of Southern Company Gas in Item 7 herein.

Competition

Electric

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

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

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

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

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

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

As of December 31, 2016, Alabama Power had cogeneration contracts in effect with nine industrial customers. Under the terms of these contracts, Alabama Power purchases excess energy generated by such companies. During 2016, Alabama Power purchased approximately 78 million KWHs from such companies at a cost of $2 million.

As of December 31, 2016, Georgia Power had contracts in effect with 29 small power producers whereby Georgia Power purchases their excess generation. During 2016, Georgia Power purchased 1.2 billion KWHs from such companies at a cost of $88 million. Georgia Power also has PPAs for electricity with six cogeneration facilities. Payments are subject to reductions for failure to meet minimum capacity output. During 2016, Georgia Power purchased 512 million KWHs at a cost of $38 million from these facilities.

Also during 2016, Georgia Power purchased energy from three customer-owned generating facilities. These customers provide only energy to Georgia Power, make no capacity commitment, and are not dispatched by Georgia Power. During 2016, Georgia Power purchased a total of 46 million KWHs from the three customers at a cost of approximately $2 million.

As of December 31, 2016, Gulf Power had agreements in effect with various industrial, commercial, and qualifying facilities pursuant to which Gulf Power purchases "as available" energy from customer-owned generation. During 2016, Gulf Power purchased 228 million KWHs from such companies for approximately $6 million.

As of December 31, 2016, Mississippi Power had one cogeneration agreement in effect with one of its industrial customers. Under the terms of this contract, Mississippi Power purchases any excess generation. During 2016, Mississippi Power did not purchase any excess generation from this customer.

Natural Gas

Southern Company Gas' regulated natural gas distribution utilities do not compete with other distributors of natural gas in their exclusive franchise territories but face competition from other energy products. Their principal competitors are electric utilities and fuel oil and propane providers serving the residential, commercial, and industrial markets in their service areas for customers who are considering switching to or from a natural gas appliance.

Competition for heating as well as general household and small commercial energy needs generally occurs at the initial installation phase when the customer or builder makes decisions as to which types of equipment to install. Customers generally use the chosen energy source for the life of the equipment.

Customer demand for natural gas could be affected by numerous factors, including:

- changes in the availability or price of natural gas and other forms of energy;
- general economic conditions;
- energy conservation, including state-supported energy efficiency programs;
- legislation and regulations;
- the cost and capability to convert from natural gas to alternative energy products; and
- technological changes resulting in displacement or replacement of natural gas appliances.

Southern Company Gas continues to develop and grow its business through the use of a variety of targeted marketing programs designed to attract new customers and to retain existing customers. These efforts include working to add residential customers, multifamily complexes, and commercial customers who might use natural gas, as well as evaluating and launching new natural gas related programs, products, and services to enhance customer growth, mitigate customer attrition, and increase operating revenues.

The natural gas-related programs generally emphasize natural gas as the fuel of choice for customers and seek to expand the use of natural gas through a variety of promotional activities. In addition, Southern Company Gas partners with third-party entities to market the benefits of natural gas appliances.

Recent advances in natural gas drilling in shale producing regions of the U.S. have resulted in historically high supplies of natural gas and relatively low prices for natural gas. The availability and affordability of natural gas have provided cost advantages and further opportunity for growth of the businesses.

Seasonality

The demand for electric power and natural gas supply is affected by seasonal differences in the weather. In most of the areas the traditional electric operating companies serve, electric power sales peak during the summer, while in most of the areas Southern Company Gas serves, natural gas demand peaks during the winter. As a result, the overall operating results of Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas in the future may fluctuate substantially on a seasonal basis. In addition, Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas have historically sold less power and natural gas when weather conditions are milder.

Regulation

State Commissions

The traditional electric operating companies and the natural gas distribution utilities are subject to the jurisdiction of their respective state PSCs or applicable state regulatory agencies. These regulatory bodies have broad powers of supervision and regulation over public utilities operating in the respective states, including their rates, service regulations, sales of securities (except for the Mississippi PSC), and, in the cases of the Georgia PSC and the Mississippi PSC, in part, retail service territories. See "Territory Served by the Southern Company System" and "Rate Matters" herein for additional information.

Federal Power Act

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

Alabama Power and Georgia Power are also subject to the provisions of the Federal Power Act or the earlier Federal Water Power Act applicable to licensees with respect to their hydroelectric developments. As of December 31, 2016, among the hydroelectric projects subject to licensing by the FERC are 14 existing Alabama Power generating stations having an aggregate

installed capacity of 1,670,000 KWs and 17 existing Georgia Power generating stations and one generating station partially owned by Georgia Power, with a combined aggregate installed capacity of 1,087,296 KWs.

In 2013, the FERC issued a new 30-year license to Alabama Power for Alabama Power's seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin). Alabama Power filed a petition requesting rehearing of the FERC order granting the relicense seeking revisions to several conditions of the license. Alabama Rivers Alliance, American Rivers, the Georgia Environmental Protection Division, and the Atlanta Regional Commission also filed petitions for rehearing of the FERC order. On April 21, 2016, the FERC issued an order granting in part and denying in part Alabama Power's rehearing request. The order also denied rehearing requests filed by Alabama Rivers Alliance, American Rivers, the Georgia Environmental Protection Division, and the Atlanta Regional Commission. On May 17, 2016, Alabama Rivers Alliance and American Rivers filed a second rehearing request and on June 15, 2016, also filed a petition for review at the U.S. Court of Appeals for the District of Columbia Circuit of the license and the rehearing denial order. The FERC issued an order on September 12, 2016 denying the second rehearing request, and American Rivers and Alabama Rivers Alliance subsequently filed an appeal of that order at the U.S. Court of Appeals for the District of Columbia Circuit. The U.S. Court of Appeals for the District of Columbia Circuit has consolidated the two appeals into one proceeding.

In 2013, Alabama Power filed an application with the FERC to relicense the Holt hydroelectric project located on the Warrior River. The current Holt license expired on August 31, 2015. Since the FERC did not act on Alabama Power's new license application prior to expiration, the FERC issued to Alabama Power an annual license authorizing continued operation of the project under the terms and conditions of the expired license until action is taken on the new license and, on December 22, 2016, issued a new 50-year license to Alabama Power.

In December 2015, the FERC issued a new 30-year license to Alabama Power for the Martin Dam project located on the Tallapoosa River. Alabama Rivers Alliance, American Rivers, the Georgia Environmental Protection Division, and the Atlanta Regional Commission filed petitions for rehearing of the FERC order, which the FERC denied on November 15, 2016.

In 2016, Georgia Power continued the process of developing an application to relicense the Wallace Dam project on the Oconee River. The current Wallace Dam project license will expire on June 1, 2020.

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

Licenses for all projects, excluding those discussed above, expire in the years 2023-2040 in the case of Alabama Power's projects and in the years 2024-2044 in the case of Georgia Power's projects.

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

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

Nuclear Regulation

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

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

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

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

Environmental Statutes and Regulations

The Southern Company system's electric utilities' operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Included are laws and regulations regarding the handling and disposal of waste and release of hazardous substances from certain current and former operating sites, and locations affected by historical operations or subject to contractual obligations. Compliance with these existing environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions or through market-based contracts. There is no assurance, however, that all such costs will be recovered. For Southern Company Gas, substantially all of these costs are related to former manufactured gas plants (MGP) sites, which are primarily recovered through existing ratemaking provisions. See Note 3 to the financial statements of Southern Company Gas under "Environmental Matters" in Item 8 herein for additional information.

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

The Southern Company system's ultimate environmental compliance strategy, including potential electric generating unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations; the time periods over which compliance with regulations is required; individual state implementation of regulations, as applicable; the outcome of any legal challenges to the environmental rules; any additional rulemaking activities in response to legal challenges and court decisions; the cost, availability, and existing inventory of emissions allowances; the impact of future changes in generation and emissions-related technology; the fuel mix of the electric utilities; and environmental remediation requirements. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. Environmental compliance spending over the next several years may differ materially from the amounts estimated. Such expenditures could affect results of operations, cash flows, and financial condition if such costs are not recovered on a timely basis through regulated rates for the traditional electric operating companies and the natural gas distribution utilities or through long-term wholesale agreements for the traditional electric operating companies and Southern Power. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for energy, which could negatively affect results of operations, cash flows, and financial condition. Also see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company, each of the traditional electric operating companies, Southern Power, and Southern Company Gas in Item 7 herein for additional information. The ultimate outcome of these matters cannot be determined at this time.

Compliance with any new federal or state legislation or regulations relating to air, water, and land resources or other environmental and health concerns could significantly affect the Southern Company system. Although new or revised environmental legislation or regulations could affect many areas of the electric utilities' and natural gas distribution utilities' operations, the full impact of any such changes cannot be determined at this time. 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 and natural gas. See "Construction Program" herein for additional information.

Rate Matters

Rate Structure and Cost Recovery Plans

Electric

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

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

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

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

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

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

Through 2015, long-term non-affiliate capacity sales from Gulf Power's ownership of Plant Scherer Unit 3 (205 MWs) provided the majority of Gulf Power's wholesale earnings. Contract expirations at the end of 2015 and the end of May 2016 related to Plant Scherer Unit 3 wholesale services had a material negative impact on Gulf Power's earnings in 2016 but did not have a material impact on Southern Company's earnings in 2016. Remaining contract sales from Plant Scherer Unit 3 cover approximately 24% of Gulf Power's ownership of the unit through 2019. On October 12, 2016, Gulf Power filed a petition (2016 Rate Case) with the Florida PSC requesting an annual increase in retail rates and charges of $106.8 million based on the projected test year of January 1, 2017 through December 31, 2017 and a retail return on equity (ROE) of 11% compared to the current retail ROE of 10.25%. The requested increase includes recovery of the portion of Plant Scherer Unit 3 that has been rededicated to serving retail customers following the contract expirations discussed above. If retail recovery of Plant Scherer Unit 3 is not approved by the Florida PSC in the 2016 Rate Case, Gulf Power may consider an asset sale. The current book

value of Gulf Power's ownership of Plant Scherer Unit 3 could exceed market value which could result in a material loss. The Florida PSC is expected to make a decision on the 2016 Rate Case in the second quarter 2017. Gulf Power has requested that the increase in base rates, if approved by the Florida PSC, become effective in July 2017. On November 2, 2016, the Florida PSC approved Gulf Power's 2017 annual cost recovery clause factors. The fuel and environmental factors include certain costs associated with the ongoing ownership and operation of Plant Scherer Unit 3. The final disposition of these costs, and the related impact on rates, is subject to the Florida PSC's ultimate ruling on whether costs associated with Plant Scherer Unit 3 are recoverable from retail customers, which is expected to be decided by the Florida PSC in the 2016 Rate Case.

Mississippi Power serves long-term contracts with rural electric cooperative associations and a municipality located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 19.8% of Mississippi Power's operating revenues in 2016 and are largely subject to rolling 10-year cancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

Natural Gas

Southern Company Gas' seven natural gas distribution utilities are subject to regulations and oversight by their respective state regulatory agencies with respect to rates charged to their customers, maintenance of accounting records, and various service and safety matters. Rates charged to these customers vary according to customer class (residential, commercial, or industrial) and rate jurisdiction. These agencies approve rates designed to provide Southern Company Gas the opportunity to generate revenues to recover all prudently incurred costs, including a return on rate base sufficient to pay interest on debt, and provide a reasonable return. Rate base generally consists of the original cost of the utility plant in service, working capital, and certain other assets, less accumulated depreciation on the utility plant in service and net deferred income tax liabilities, and may include certain other additions or deductions.

With the exception of Atlanta Gas Light Company, which operates in a deregulated environment in which gas marketers rather than a traditional utility sell natural gas to end-use customers and earns revenue by charging rates to its customers based primarily on monthly fixed charges that are set by the Georgia PSC, the earnings of the natural gas distribution utilities can be affected by customer consumption patterns that are largely a function of weather conditions and price levels for natural gas.

The natural gas distribution utilities, excluding Atlanta Gas Light Company, are authorized to use natural gas cost recovery mechanisms that allow them to adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure they recover all of the costs prudently incurred in purchasing gas for their customers. In addition to natural gas cost recovery mechanisms, the natural gas distribution utilities have other cost recovery mechanisms, such as regulatory riders, which vary by utility but allow recovery of certain costs, such as those related to infrastructure replacement programs as well as environmental remediation and energy efficiency plans.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Regulatory Matters – Utility Regulation and Rate Design" of Southern Company Gas in Item 7 herein and Note 3 to the financial statements of Southern Company Gas under "Regulatory Matters" in Item 8 herein for a discussion of rate matters and certain cost recovery mechanisms.

Integrated Resource Planning

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

Certain of the traditional electric operating companies are required to file IRPs with their respective state PSC as discussed below.

Georgia Power

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

See Note 3 to the financial statements of Southern Company under "Regulatory Matters – Georgia Power – Rate Plans," "– Integrated Resource Plan," and "– Nuclear Construction" and Note 3 to the financial statements of Georgia Power under "Retail

Regulatory Matters – Rate Plans," "– Integrated Resource Plan," and "– Nuclear Construction" in Item 8 herein for additional information.

Gulf Power

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

Gulf Power's most recent 10-year site plan was classified by the Florida PSC as "suitable" in November 2016. Gulf Power's most recent 10-year site plan and environmental compliance plan identify environmental regulations and potential legislation or regulation that would impose mandatory restrictions on greenhouse gas emissions. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Environmental Statutes and Regulations – Coal Combustion Residuals," and "– Global Climate Issues" of Gulf Power in Item 7 herein. Gulf Power continues to evaluate the economics of various potential planning scenarios for units at certain Gulf Power coal-fired generating plants as EPA and other regulations develop.

As a result of the cost to comply with environmental regulations imposed by the EPA, Gulf Power retired its coal-fired generation at Plant Smith Units 1 and 2 (357 MWs) on March 31, 2016. Gulf Power filed a petition with the Florida PSC requesting permission to recover the remaining net book value of Plant Smith Units 1 and 2 and the remaining materials and supplies associated with these units as of the retirement date. On August 29, 2016, the Florida PSC approved Gulf Power's request to reclassify these costs, totaling approximately $63 million, to a regulatory asset for recovery over a period to be decided in the 2016 Rate Case. The ultimate outcome of this matter cannot be determined at this time.

Mississippi Power

Mississippi Power's 2010 IRP indicated that Mississippi Power plans to construct the Kemper IGCC to meet its identified needs, to add environmental controls at Plant Daniel Units 1 and 2, to defer environmental controls at Plant Watson Units 4 and 5, and to continue operation of the combined cycle Plant Daniel Units 3 and 4. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" and "– Global Climate Issues" of Mississippi Power in Item 7 herein. In 2014, Mississippi Power entered into a settlement agreement with the Sierra Club that, among other things, required the Sierra Club to dismiss or withdraw all pending legal and regulatory challenges to the Kemper IGCC and the flue gas desulfurization system project at Plant Daniel Units 1 and 2, which also occurred in 2014. In addition, and consistent with Mississippi Power's ongoing evaluation of recent environmental rules and regulations, Mississippi Power agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source Plant Sweatt Units 1 and 2 (80 MWs) no later than December 2018 (and the units were retired in July 2016). Mississippi Power also agreed that it would cease burning coal or other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and begin operating those units solely on natural gas no later than April 2015 (which occurred in April 2015) and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) no later than April 2016 (which occurred in February and March 2016, respectively), and begin operating those units solely on natural gas (which occurred in June and July 2016, respectively).

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

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

Employee Relations

The Southern Company system had a total of 32,015 employees on its payroll at December 31, 2016.

	Employees at December 31, 2016
Alabama Power	6,805
Georgia Power	7,527
Gulf Power	1,352
Mississippi Power	1,484
PowerSecure	1,051
SCS	4,341
Southern Company Gas	5,292
Southern Nuclear	3,928
Southern Power*	0
Other	235
Total	32,015

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

The traditional electric operating companies and the natural gas distribution utilities have separate agreements with local unions of the IBEW and the Utilities Workers Union of America generally covering wages, working conditions, and procedures for handling grievances and arbitration. These agreements apply with certain exceptions to operating, maintenance, and construction employees.

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

Georgia Power has an agreement with the IBEW covering wages and working conditions, which is in effect through June 30, 2021.

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

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

Southern Nuclear has a five-year agreement with the IBEW covering certain employees at Plants Hatch and Vogtle which is in effect through June 30, 2021. A five-year agreement between Southern Nuclear and the IBEW representing certain employees at Plant Farley is in effect through August 15, 2019. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

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

The natural gas distribution utilities have separate agreements with local unions of the IBEW and Utilities Workers Union of America covering wages, working conditions, and procedures for handling grievances and arbitration. Nicor Gas' agreement with the IBEW is effective through February 28, 2018. Virginia Natural Gas, Inc.'s agreement with the IBEW is effective through May 16, 2019. Elizabethtown Gas' agreement with the Utility Workers Union of America is effective through November 20, 2019. The agreements also make the terms of the Southern Company Gas pension plan subject to collective bargaining with the unions when significant changes to the benefit accruals are considered by Southern Company Gas.

Item 1A. RISK FACTORS

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

UTILITY REGULATORY, LEGISLATIVE, AND LITIGATION RISKS

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

Southern Company and its subsidiaries, including the traditional electric operating companies, Southern Power, and Southern Company Gas, are subject to substantial regulation from federal, state, and local regulatory agencies. Southern Company and its subsidiaries are required to comply with numerous laws and regulations and to obtain numerous permits, approvals, and certificates from the governmental agencies that regulate various aspects of their businesses, including rates and charges, service regulations, retail service territories, sales of securities, sales and marketing of energy-related products and services, incurrence of indebtedness, asset acquisitions and sales, accounting and tax policies and practices, physical and cyber security policies and practices, and the construction and operation of electric generating facilities, as well as transmission, storage, transportation, and distribution facilities for the electric and natural gas businesses. For example, the respective state PSC or other applicable state regulatory agency must approve the traditional electric operating companies' requested rates for retail electric customers and the natural gas distribution utilities' requested rates for gas distribution operations customers. The traditional electric operating companies and the natural gas distribution utilities seek to recover their costs (including a reasonable return on invested capital) through their retail rates, and a state PSC or other applicable state regulatory agency, in a future rate proceeding, may alter the timing or amount of certain costs for which recovery is allowed or modify the current authorized rate of return. Rate refunds may also be required. Additionally, the rates charged to wholesale customers by the traditional electric operating companies and by Southern Power must be approved by the FERC. These wholesale rates could be affected by changes to Southern Power's and the traditional electric operating companies' ability to conduct business pursuant to FERC market-based rate authority. The FERC rules related to retaining the authority to sell electricity at market-based rates in the wholesale markets are important for the traditional electric operating companies and Southern Power if they are to remain competitive in the wholesale markets in which they operate.

The impact of any future revision or changes in interpretations of existing regulations or the adoption of new laws and regulations applicable to Southern Company or any of its subsidiaries is uncertain. Changes in regulation or the imposition of additional regulations could influence the operating environment of Southern Company and its subsidiaries and may result in substantial costs or otherwise negatively affect their results of operations.

The Southern Company system's costs of compliance with environmental laws are significant. The costs of compliance with current and future environmental laws, including laws and regulations designed to address air quality, greenhouse gases (GHG), water quality, waste, and other matters and the incurrence of environmental liabilities could negatively impact the net income, cash flows, and financial condition of Southern Company, the traditional electric operating companies, Southern Power, and/or Southern Company Gas.

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

The EPA has adopted and is in the process of implementing regulations governing air and water quality, including the emission of nitrogen oxide, sulfur dioxide, fine particulate matter, ozone, mercury, and other air pollutants under the Clean Air Act and regulations governing cooling water intake structures and effluent guidelines for steam electric generating plants under the Clean Water Act. The EPA has also finalized regulations governing the disposal of CCR, including coal ash and gypsum, in landfills and surface impoundments at active power generation plants. The EPA has also finalized regulations, which are currently stayed by the U.S. Supreme Court, limiting CO_2 emissions from fossil fuel-fired electric generating units.

Additionally, environmental laws and regulations covering the handling and disposal of waste and release of hazardous substances could require the Southern Company system to incur substantial costs to clean up affected sites, including certain current and former operating sites, and locations affected by historical operations or subject to contractual obligations.

Existing environmental laws and regulations may be revised or new laws and regulations related to air quality, GHG, water quality, waste, endangered species, or other environmental and health concerns may be adopted or become applicable to the traditional electric operating companies, Southern Power, and/or Southern Company Gas.

Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, releases of regulated substances, and alleged exposure to regulated substances, and/or requests for injunctive relief in connection with such matters.

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

Environmental compliance spending over the next several years may differ materially from the amounts estimated. Such expenditures could affect unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered on a timely basis through regulated rates for the traditional electric operating companies and the natural gas distribution utilities or through long-term wholesale agreements for the traditional electric operating companies and Southern Power. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for energy, which could negatively affect results of operations, cash flows, and financial condition. Additionally, if Southern Company, any traditional electric operating company, Southern Power, or Southern Company Gas fails to comply with environmental laws and regulations, even if caused by factors beyond its control, that failure may result in the assessment of civil or criminal penalties and fines and/or remediation costs.

The Southern Company system may be exposed to regulatory and financial risks related to the impact of climate change legislation and regulation.

Since the late 1990s, the U.S. Congress, the EPA, federal courts, and various states have considered, and at times have adopted, climate change policies and proposals to reduce GHG emissions, mandate renewable energy, and/or impose energy efficiency standards. Clean Air Act regulation and/or future GHG or renewable energy legislation requiring limits or reductions in emissions could cause the Southern Company system to incur expenditures and make fundamental business changes to achieve limits and reduce GHG emissions. Internationally, the United Nations Framework Convention on Climate Change, which the United States has ratified, considers addressing climate change. The 21st Conference of the Parties met in late 2015 and resulted in the adoption of the Paris Agreement, which established a non-binding universal framework for addressing GHG emissions based on nationally determined contributions.

In October 2015, the EPA published two final actions that would limit CO_2 emissions from fossil fuel-fired electric generating units. One of the final actions contains specific emission standards governing CO_2 emissions from new, modified, and reconstructed units. The other final action, known as the Clean Power Plan, establishes guidelines for states to develop plans to meet EPA-mandated CO_2 emission rates for existing units. The EPA's final guidelines require state plans to meet interim CO_2 performance rates between 2022 and 2029 and final rates in 2030 and thereafter. The proposed guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions. On February 9, 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan, pending disposition of petitions for its review with the courts. The stay will remain in effect through the resolution of the litigation, whether resolved in the U.S. Court of Appeals for the District of Columbia Circuit or the U.S. Supreme Court.

Costs associated with these actions could be significant to the utility industry and the Southern Company system. However, the ultimate financial and operational impact of the final rules on the Southern Company system cannot be determined at this time and will depend upon numerous factors, including the Southern Company system's ongoing review of the final rules; the outcome of legal challenges, including legal challenges filed by the traditional electric operating companies; individual state implementation of the EPA's final guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in electric

generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement generation capacity; and the time periods over which compliance will be required.

Because natural gas is a fossil fuel with lower carbon content relative to other traditional fuels, future carbon constraints may create additional demand for natural gas, both for production of electricity and direct use in homes and businesses. The impact is already being seen in the power production sector due to both environmental regulations and low natural gas costs. Future regulation of methane, a GHG and primary constituent of natural gas, could likewise result in increased costs to the Southern Company system and affect the demand for natural gas as well as the prices charged to customers and the competitive position of natural gas.

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

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

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

The FERC rules related to transmission are intended to spur the development of new transmission infrastructure to promote and encourage the integration of renewable sources of supply as well as facilitate competition in the wholesale market by providing more choices to wholesale power customers. In addition to the impacts on transactions contemplating physical delivery of energy, financial laws and regulations also impact power hedging and trading based on futures contracts and derivatives that are traded on various commodities exchanges as well as over-the-counter. Finally, technology changes in the power and fuel industries continue to create significant impacts to wholesale transaction cost structures. The impact of these and other such developments and the effect of changes in levels of wholesale supply and demand is uncertain. The financial condition, net income, and cash flows of Southern Company, the traditional electric operating companies, and Southern Power could be adversely affected by these and other changes.

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

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

Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas may be materially impacted by potential tax reform legislation.

Current proposals related to potential tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals, including potential changes to the availability or realizability of investment tax credits and PTCs, is dependent upon the final form of any legislation enacted and the related transition rules and cannot be determined at this time, but could have a material impact on the financial statements of Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas.

OPERATIONAL RISKS

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

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

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

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

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

Alabama Power owns, and contracts for the operation of, two nuclear units and Georgia Power holds undivided interests in, and contracts for the operation of, four existing nuclear units. The six existing units are operated by Southern Nuclear and represent approximately 3,680 MWs, or 8%, of the Southern Company system's electric generation capacity as of December 31, 2016. In addition, these units generated approximately 23% and 24% of the total KWHs generated by Alabama Power and Georgia Power, respectively, in the year ended December 31, 2016. In addition, Southern Nuclear, on behalf of Georgia Power and the other co-owners, is overseeing the construction of Plant Vogtle Units 3 and 4. Due solely to the increase in nuclear generating capacity, the below risks are expected to increase incrementally once Plant Vogtle Units 3 and 4 are operational. Nuclear facilities are subject to environmental, safety, health, operational, and financial risks such as:

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

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

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

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

Transporting and storing natural gas involves risks that may result in accidents and other operating risks and costs.

Southern Company Gas' natural gas distribution and storage activities involve a variety of inherent hazards and operating risks, such as leaks, accidents, explosions, and mechanical problems, which could result in serious injury to employees and non-employees, loss of human life, significant damage to property, environmental pollution, and impairment of its operations. The location of pipelines and storage facilities near populated areas could increase the level of damage resulting from these risks. The occurrence of any of these events not fully covered by insurance could adversely affect Southern Company Gas' and Southern Company's financial condition and results of operations.

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

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

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

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

The Southern Company system may not be able to obtain adequate natural gas and other fuel supplies required to operate the traditional electric operating companies' and Southern Power's electric generating plants or serve Southern Company Gas' natural gas customers.

The traditional electric operating companies and Southern Power purchase fuel, including coal, natural gas, uranium, fuel oil, and biomass, as applicable, from a number of suppliers. Disruption in the delivery of fuel, including disruptions as a result of, among other things, transportation delays, weather, labor relations, force majeure events, or environmental regulations affecting

any of these fuel suppliers, could limit the ability of the traditional electric operating companies and Southern Power to operate certain facilities, which could result in higher fuel and operating costs and potentially reduce the net income of the affected traditional electric operating company or Southern Power and Southern Company.

Southern Company Gas' primary business is the distribution and sale of natural gas through its regulated and unregulated subsidiaries. Natural gas supplies can be subject to disruption in the event production or distribution is curtailed, such as in the event of a hurricane or a pipeline failure. Southern Company Gas also relies on natural gas pipelines and other storage and transportation facilities owned and operated by third parties to deliver natural gas to wholesale markets and to Southern Company Gas' distribution systems. The availability of shale gas and potential regulations affecting its accessibility may have a material impact on the supply and cost of natural gas. Disruption in natural gas supplies could limit the ability to fulfill these contractual obligations.

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

The traditional electric operating companies are also dependent on coal for a portion of their electric generating capacity. The traditional electric operating companies depend on coal supply contracts, and the counterparties to these agreements may not fulfill their obligations to supply coal to the traditional electric operating companies. The suppliers under these agreements may experience financial or technical problems that inhibit their ability to fulfill their obligations to the traditional electric operating companies. In addition, the suppliers under these agreements may not be required to supply coal to the traditional electric operating companies under certain circumstances, such as in the event of a natural disaster. If the traditional electric operating companies are unable to obtain their coal requirements under these contracts, the traditional electric operating companies may be required to purchase their coal requirements at higher prices, which may not be recoverable through rates.

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

Most of Southern Power's generating capacity has been sold to purchasers under PPAs. Southern Power's top three customers, Georgia Power, Duke Energy Corporation, and San Diego Gas & Electric accounted for 16.5%, 7.8%, and 5.7%, respectively, of Southern Power's total revenues for the year ended December 31, 2016. In addition, the traditional electric operating companies enter into PPAs with non-affiliated parties. Revenues are dependent on the continued performance by the purchasers of their obligations under these PPAs. The failure of one of the purchasers to perform its obligations could have a negative impact on the net income and cash flows of the affected traditional electric operating company or Southern Power and of Southern Company. Although the credit evaluations undertaken and contractual protections implemented by Southern Power and the traditional electric operating companies take into account the possibility of default by a purchaser, actual exposure to a default by a purchaser may be greater than predicted or specified in the applicable contract.

Additionally, neither Southern Power nor any traditional electric operating company can predict whether the PPAs will be renewed at the end of their respective terms or on what terms any renewals may be made. As an example, Gulf Power had long-term sales contracts to cover 100% of its ownership share of Plant Scherer Unit 3 (205 MWs) and these capacity revenues represented 82% of Gulf Power's total wholesale capacity revenues for 2015. Following contract expirations at the end of 2015 and the end of May 2016, Gulf Power's remaining contracted sales from the unit cover approximately 24% of Gulf Power's ownership of the unit through 2019. The expiration of these contracts had a material negative impact on Gulf Power's earnings in 2016 and may continue to have a material negative impact in future years. In addition, the failure of the traditional electric operating companies or Southern Power to satisfy minimum operational or availability requirements under these PPAs could result in payment of damages or termination of the PPAs.

The asset management arrangements between Southern Company Gas' wholesale gas services and Southern Company Gas' regulated operating companies, and between Southern Company Gas' wholesale gas services and its non-affiliated customers, may not be renewed or may be renewed at lower levels, which could have a significant impact on Southern Company Gas' financial results.

Southern Company Gas' wholesale gas services currently manages the storage and transportation assets of Atlanta Gas Light Company, Virginia Natural Gas, Inc., Elizabethtown Gas, Florida City Gas, Chattanooga Gas Company, and Elkton Gas. The

profits earned from the management of these affiliate assets are shared with the respective affiliate's customers (and for Atlanta Gas Light Company with the Georgia PSC's Universal Service Fund), except for Chattanooga Gas Company and Elkton Gas where wholesale gas services are provided under annual fixed-fee agreements. These asset management agreements are subject to regulatory approval and such agreements may not be renewed or may be renewed with less favorable terms.

Southern Company Gas' wholesale gas services also has asset management agreements with certain non-affiliated customers and its financial results could be significantly impacted if these agreements are not renewed or are amended or renewed with less favorable terms. Sustained low natural gas prices could reduce the demand for these types of asset management arrangements.

Increased competition could negatively impact Southern Company's and its subsidiaries' revenues, results of operations, and financial condition.

The energy industry is highly competitive and complex and the Southern Company system faces increasing competition from other companies that supply energy or generation and storage technologies. Changes in technology may make the Southern Company system's electric generating facilities owned by the traditional electric operating companies and Southern Power less competitive. Southern Company Gas' business is dependent on natural gas prices remaining competitive as compared to other forms of energy. Southern Company Gas also faces competition in its unregulated markets.

A key element of the business models of the traditional electric operating companies and Southern Power is that generating power at central station power plants achieves economies of scale and produces power at a competitive cost. There are distributed generation and storage technologies that produce and store power, including fuel cells, microturbines, wind turbines, solar cells, and batteries. Advances in technology or changes in laws or regulations could reduce the cost of these or other alternative methods of producing power to a level that is competitive with that of most central station power electric production or result in smaller-scale, more fuel efficient, and/or more cost effective distributed generation that allows for increased self-generation by customers. Broader use of distributed generation by retail energy customers may also result from customers' changing perceptions of the merits of utilizing existing generation technology or tax or other economic incentives. Additionally, a state PSC or legislature may modify certain aspects of the traditional electric operating companies' business as a result of these advances in technology.

It is also possible that rapid advances in central station power generation technology could reduce the value of the current electric generating facilities owned by the traditional electric operating companies and Southern Power. Changes in technology could also alter the channels through which electric customers buy or utilize power, which could reduce the revenues or increase the expenses of Southern Company, the traditional electric operating companies, or Southern Power.

Southern Company Gas' gas marketing services is affected by competition from other energy marketers providing similar services in Southern Company Gas' service territories, most notably in Illinois and Georgia. Southern Company Gas' wholesale gas services competes for sales with national and regional full-service energy providers, energy merchants and producers, and pipelines based on the ability to aggregate competitively-priced commodities with transportation and storage capacity. Southern Company Gas competes with natural gas facilities in the Gulf Coast region of the U.S., as the majority of the existing and proposed high deliverability salt-dome natural gas storage facilities in North America are located in the Gulf Coast region. Storage values have begun to recover from the declines experienced over the past several years due to low natural gas prices and low volatility and Southern Company Gas expects this trend to continue during the remainder of 2017.

If new technologies become cost competitive and achieve sufficient scale, the market share of the traditional electric operating companies, Southern Power, and Southern Company Gas could be eroded, and the value of their respective electric generating facilities or natural gas distribution and storage facilities could be reduced. Additionally, Southern Company Gas' market share could be reduced if Southern Company Gas cannot remain price competitive in its unregulated markets. If state PSCs or other applicable state regulatory agencies fail to adjust rates to reflect the impact of any changes in loads, increasing self-generation, and the growth of distributed generation, the financial condition, results of operations, and cash flows of Southern Company and the affected traditional electric operating company or Southern Company Gas could be materially adversely affected.

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

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

and its subsidiaries are unable to successfully attract and retain an appropriately qualified workforce, results of operations could be negatively impacted.

CONSTRUCTION RISKS

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

General

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

- shortages and inconsistent quality of equipment, materials, and labor;
- changes in labor costs and productivity;
- work stoppages;
- contractor or supplier delay or non-performance under construction, operating, or other agreements or non-performance by other major participants in construction projects;
- delays in or failure to receive necessary permits, approvals, tax credits, and other regulatory authorizations;
- delays associated with start-up activities, including major equipment failure and system integration, and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by any PSC or other applicable state regulatory agency);
- operational readiness, including specialized operator training and required site safety programs;
- impacts of new and existing laws and regulations, including environmental laws and regulations;
- the outcome of legal challenges to projects, including legal challenges to regulatory approvals;
- failure to construct in accordance with permitting and licensing requirements;
- failure to satisfy any environmental performance standards and the requirements of tax credits and other incentives;
- continued public and policymaker support for such projects;
- adverse weather conditions or natural disasters;
- other unforeseen engineering or design problems;
- changes in project design or scope;
- environmental and geological conditions;
- delays or increased costs to interconnect facilities to transmission grids; and
- unanticipated cost increases, including materials and labor, and increased financing costs as a result of changes in market interest rates or as a result of construction schedule delays.

If a traditional electric operating company, Southern Power, or Southern Company Gas is unable to complete the development or construction of a project or decides to delay or cancel construction of a project, it may not be able to recover its investment in that project and may incur substantial cancellation payments under equipment purchase orders or construction contracts. Additionally, each Southern Company Gas pipeline construction project involves separate joint venture participants. Even if a construction project (including a joint venture construction project) is completed, the total costs may be higher than estimated and the applicable traditional electric operating company or the natural gas distribution utility may not be able to recover such expenditures through regulated rates. In addition, construction delays and contractor performance shortfalls can result in the loss of revenues and may, in turn, adversely affect the net income and financial position of a traditional electric operating company, Southern Power, or Southern Company Gas and of Southern Company.

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

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

The two largest construction projects currently underway in the Southern Company system are the construction of Plant Vogtle Units 3 and 4 and the Kemper IGCC. In addition, Southern Power has 567 MWs of natural gas and renewable generation under construction at three project sites.

Plant Vogtle Units 3 and 4 construction and rate recovery

Southern Nuclear, on behalf of Georgia Power and the other co-owners, is overseeing the construction of and will operate Plant Vogtle Units 3 and 4 (each, an approximately 1,100 MW AP1000 nuclear generating unit). Georgia Power owns 45.7% of the new units. There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, and additional challenges may arise as construction proceeds.

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

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

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

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

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4 with a certified capital cost of $4.418 billion. On December 20, 2016, the Georgia PSC voted to approve a settlement agreement (Vogtle Cost Settlement Agreement) resolving certain prudence matters, including that (i) the in-service capital cost forecast will be adjusted to $5.680 billion (Revised Forecast), which includes a contingency of $240 million above Georgia Power's current forecast of $5.440 billion, (ii) capital costs incurred up to the Revised Forecast will be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, and (iii) Georgia Power would have the burden to show that any capital costs above the Revised Forecast are reasonable and prudent.

Under the terms of the Vogtle Cost Settlement Agreement, the certified in-service capital cost for purposes of calculating Georgia Power's Nuclear Construction Cost Recovery (NCCR) tariff will remain at $4.418 billion. Construction capital costs above $4.418 billion will accrue allowance for funds used during construction (AFUDC) through the date each unit is placed in service. The ROE used to calculate the NCCR tariff was reduced from 10.95% (the ROE rate setting point authorized by the

Georgia PSC in the Alternative Rate Plan approved by the Georgia PSC for the years 2014 through 2016) to 10.00% effective January 1, 2016. For purposes of the AFUDC calculation, the ROE on costs between $4.418 billion and $5.440 billion will also be 10.00% and the ROE on any amounts above $5.440 billion would be Georgia Power's average cost of long-term debt. If the Georgia PSC adjusts Georgia Power's ROE rate setting point in a rate case prior to Plant Vogtle Units 3 and 4 being placed into retail rate base, then the ROE for purposes of calculating both the NCCR tariff and AFUDC will likewise be 95 basis points lower than the revised ROE rate setting point. If Plant Vogtle Units 3 and 4 are not placed in service by December 31, 2020, then (i) the ROE for purposes of calculating the NCCR tariff will be reduced an additional 300 basis points, or $8 million per month, and may, at the Georgia PSC's discretion, be accrued to be used for the benefit of customers, until such time as the units are placed in service and (ii) the ROE used to calculate AFUDC will be Georgia Power's average cost of long-term debt.

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

As of December 31, 2016, Georgia Power had borrowed $2.6 billion related to Plant Vogtle Units 3 and 4 costs through a loan guarantee agreement between Georgia Power and the DOE and a multi-advance credit facility among Georgia Power, the DOE, and the FFB. See Note 6 to the financial statements of Southern Company and Georgia Power under "DOE Loan Guarantee Borrowings" in Item 8 herein for additional information, including applicable covenants, events of default, and mandatory prepayment events.

Processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse Design Control Document for the AP1000 nuclear reactor and the combined construction and operating licenses, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance matters, including the timely resolution of Inspections, Tests, Analyses, and Acceptance Criteria and the related approvals by the NRC, may arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Vogtle Owners or the Contractor or to both.

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

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

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

See Note 3 to the financial statements of Southern Company under "Regulatory Matters - Georgia Power - Nuclear Construction" and of Georgia Power under "Retail Regulatory Matters - Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

Kemper IGCC construction and rate recovery

Mississippi Power continues to progress toward completing the construction and start-up of the Kemper IGCC, which was approved by the Mississippi PSC in the 2010 certificate of public convenience and necessity (CPCN) proceedings, subject to a construction cost cap of $2.88 billion, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (Initial DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital

(which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions). The current cost estimate for the Kemper IGCC in total is approximately $6.99 billion, which includes approximately $5.64 billion of costs subject to the construction cost cap and is net of the $137 million in additional grants from the DOE received on April 8, 2016 (Additional DOE Grants), which are expected to be used to reduce future rate impacts to customers. Mississippi Power does not intend to seek any rate recovery for any related costs that exceed the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. Through December 31, 2016, in the aggregate, Southern Company and Mississippi Power have incurred charges of $2.76 billion ($1.71 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC. The current cost estimate includes costs through March 15, 2017.

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

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

Any extension of the in-service date beyond mid-March 2017 is currently estimated to result in additional base costs of approximately $25 million to $35 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. Additional costs may be required for remediation of any further equipment and/or design issues identified. Any extension of the in-service date with respect to the Kemper IGCC beyond mid-March 2017 would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $16 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees of approximately $3 million per month. Further cost increases and/or extensions of the expected in-service date may result from factors including, but not limited to, difficulties integrating the systems required for sustained operations, sustaining nitrogen supply, major equipment failure, unforeseen engineering or design problems including any repairs and/or modifications to systems, and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC).

Upon placing the remainder of the plant in service, Mississippi Power will be primarily focused on completing the regulatory cost recovery process. In December 2015, the Mississippi PSC issued an order, based on a stipulation between Mississippi Power and the Mississippi Public Utilities Staff (MPUS), authorizing rates that provide for the recovery of approximately $126 million annually related to Kemper IGCC assets previously placed in service.

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

estimates reflect ultimate results similar to those presented in the 2010 CPCN proceedings, the ramp up period for the current estimates reflects a lower starting point and a slower escalation rate.

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

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

Mississippi Power is required to file a rate case to address Kemper IGCC cost recovery by June 3, 2017 (2017 Rate Case). Costs incurred through December 31, 2016 totaled $6.73 billion, net of the Initial and Additional DOE Grants. Of this total, $2.76 billion of costs has been recognized through income as a result of the $2.88 billion cost cap, $0.84 billion is included in retail and wholesale rates for the assets in service, and the remainder will be the subject of the 2017 Rate Case to be filed with the Mississippi PSC and expected subsequent wholesale Municipal and Rural Associations rate filing with the FERC. Mississippi Power continues to believe that all costs related to the Kemper IGCC have been prudently incurred in accordance with the requirements of the 2012 MPSC order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC. Mississippi Power also recognizes significant areas of potential challenge during future regulatory proceedings (and any subsequent, related legal challenges) exist. As described further herein, these challenges include, but are not limited to, prudence issues associated with capital costs, financing costs (AFUDC), and future operating costs, net of chemical revenues; potential operating parameters; income tax issues; costs deferred as regulatory assets; and the 15% portion of the project previously contracted to SMEPA.

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

Mississippi Power has evaluated various scenarios in connection with its processes to prepare the 2017 Rate Case and Southern Company and Mississippi Power have recognized an additional $80 million charge to income, which is the estimated minimum probable amount of the $3.31 billion of Kemper IGCC costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017. Given the variety of potential scenarios and the uncertainty of the outcome of future regulatory proceedings with the Mississippi PSC (and any subsequent related legal challenges), the ultimate

outcome of these matters cannot now be determined but could result in further charges that could have a material impact on Southern Company's and Mississippi Power's results of operations, financial condition, and liquidity.

Southern Company and Mississippi Power are defendants in various lawsuits that allege improper disclosure about the Kemper IGCC. While Southern Company and Mississippi Power believe that these lawsuits are without merit, an adverse outcome could have a material impact on Southern Company's and Mississippi Power's results of operations, financial condition, and liquidity. In addition, the SEC is conducting a formal investigation of Southern Company and Mississippi Power concerning the estimated costs and expected in-service date of the Kemper IGCC. Southern Company and Mississippi Power believe the investigation is focused primarily on periods subsequent to 2010 and on accounting matters, disclosure controls and procedures, and internal controls over financial reporting associated with the Kemper IGCC.

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

See Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

Southern Company Gas' significant investments in pipelines and pipeline development projects involve financial and execution risks.

Southern Company Gas has made significant investments in existing pipelines and pipeline development projects. Many of the existing pipelines are, and when completed many of the pipeline development projects will be, operated by third parties. If one of these agents fails to perform in a proper manner, the value of the investment could decline and Southern Company Gas could lose part or all of the investment. In addition, from time to time, Southern Company Gas may be required to contribute additional capital to a pipeline joint venture or guarantee the obligations of such joint venture.

With respect to certain pipeline development projects, Southern Company Gas will rely on its joint venture partners for construction management and will not exercise direct control over the process. All of the pipeline development projects are dependent on contractors for the successful and timely completion of the projects. Further, the development of pipeline projects involves numerous regulatory, environmental, construction, safety, political, and legal uncertainties and may require the expenditure of significant amounts of capital. These projects may not be completed on schedule, at the budgeted cost, or at all. There may be cost overruns and construction difficulties that cause Southern Company Gas' capital expenditures to exceed its initial expectations. Moreover, Southern Company Gas' revenues will not increase immediately upon the expenditure of funds on a pipeline project. Pipeline construction occurs over an extended period of time and Southern Company Gas will not receive material increases in revenues until the project is placed in service.

The occurrence of any of the foregoing events could adversely affect the results of operations, cash flows, and financial condition of Southern Company Gas and Southern Company.

FINANCIAL, ECONOMIC, AND MARKET RISKS

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

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

- prevailing market prices for coal, natural gas, uranium, fuel oil, biomass, and other fuels, as applicable, used in the generation facilities of the traditional electric operating companies and Southern Power and, in the case of natural gas, distributed by Southern Company Gas, including associated transportation costs, and supplies of such commodities;
- demand for energy and the extent of additional supplies of energy available from current or new competitors;
- liquidity in the general wholesale electricity and natural gas markets;
- weather conditions impacting demand for electricity and natural gas;
- seasonality;
- transmission or transportation constraints, disruptions, or inefficiencies;
- availability of competitively priced alternative energy sources;
- forced or unscheduled plant outages for the Southern Company system, its competitors, or third party providers;
- the financial condition of market participants;

- the economy in the Southern Company system's service territory, the nation, and worldwide, including the impact of economic conditions on demand for electricity and the demand for fuels, including natural gas;
- natural disasters, wars, embargos, acts of terrorism, and other catastrophic events; and
- federal, state, and foreign energy and environmental regulation and legislation.

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

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

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

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

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

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

In addition, the adoption of technology by customers can have both positive and negative impacts on sales. Many new technologies utilize less energy than in the past. However, new electric and natural gas technologies such as electric and natural gas vehicles can create additional demand. The Southern Company system uses best available methods and experience to incorporate the effects of changes in customer behavior, state and federal programs, PSC or other applicable state regulatory agency mandates, and technology, but the Southern Company system's planning processes may not appropriately estimate and incorporate these effects.

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

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

Electric power and natural gas supply are generally seasonal businesses. In many parts of the country, demand for power peaks during the summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter months. In most of the areas the traditional electric operating companies serve, electric power sales peak during the summer,

while in most of the areas Southern Company Gas serves, natural gas demand peaks during the winter. As a result, the overall operating results of Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas may fluctuate substantially on a seasonal basis. In addition, the traditional electric operating companies, Southern Power, and Southern Company Gas have historically sold less power and natural gas when weather conditions are milder. Unusually mild weather in the future could reduce the revenues, net income, and available cash of Southern Company, the traditional electric operating companies, Southern Power, and/or Southern Company Gas.

In addition, volatile or significant weather events could result in substantial damage to the transmission and distribution lines of the traditional electric operating companies, the generating facilities of the traditional electric operating companies and Southern Power, and the natural gas distribution and storage facilities of Southern Company Gas. The traditional electric operating companies, Southern Power, and Southern Company Gas have significant investments in the Atlantic and Gulf Coast regions and Southern Power has wind and natural gas investments in various states, including Maine, Minnesota, Oklahoma, and Texas, which could be subject to severe weather, as well as solar investments in various states, including California, which could be subject to natural disasters. Further, severe drought conditions can reduce the availability of water and restrict or prevent the operation of certain generating facilities.

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

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

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

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

Southern Company and its subsidiaries may face significant competition for transactional opportunities and anticipated transactions may not be completed on acceptable terms or at all. In addition, these transactions are intended to, but may not, result in the generation of cash or income, the realization of savings, the creation of efficiencies, or the reduction of risk. These transactions may also affect the liquidity, results of operations, and financial condition of Southern Company and its subsidiaries.

These transactions also involve risks, including:

- they may not result in an increase in income or provide an adequate return on capital or other anticipated benefits;
- they may result in Southern Company or its subsidiaries entering into new or additional lines of business, which may have new or different business or operational risks;
- they may not be successfully integrated into the acquiring company's operations and/or internal control processes;
- the due diligence conducted prior to a transaction may not uncover situations that could result in financial or legal exposure or the acquiring company may not appropriately evaluate the likelihood or quantify the exposure from identified risks;
- they may result in decreased earnings, revenues, or cash flow;
- expected benefits of a transaction may be dependent on the cooperation or performance of a counterparty; or
- for the traditional electric operating companies, costs associated with such investments that were expected to be recovered through rates may not be recoverable.

Southern Company and Southern Company Gas are holding companies and are dependent on cash flows from their respective subsidiaries to meet their ongoing and future financial obligations, including making interest and principal payments on outstanding indebtedness and, for Southern Company, to pay dividends on its common stock.

Southern Company and Southern Company Gas are holding companies and, as such, they have no operations of their own. Substantially all of Southern Company's and Southern Company Gas' respective consolidated assets are held by subsidiaries. A significant portion of Southern Company Gas' debt is issued by its 100%-owned subsidiary, Southern Company Gas Capital, and is fully and unconditionally guaranteed by Southern Company Gas. Southern Company's and Southern Company Gas' ability to meet their respective financial obligations, including making interest and principal payments on outstanding indebtedness, and, for Southern Company, to pay dividends on its common stock, is primarily dependent on the net income and cash flows of their respective subsidiaries and the ability of those subsidiaries to pay upstream dividends or to repay borrowed funds. Prior to funding Southern Company or Southern Company Gas, the respective subsidiaries have regulatory restrictions and financial obligations that must be satisfied, including among others, debt service and preferred and preference stock dividends. These subsidiaries are separate legal entities and have no obligation to provide Southern Company or Southern Company Gas with funds. In addition, Southern Company and Southern Company Gas may provide capital contributions or debt financing to subsidiaries under certain circumstances, which would reduce the funds available to meet their respective financial obligations, including making interest and principal payments on outstanding indebtedness, and to pay dividends on Southern Company's common stock.

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

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

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

Southern Company, the traditional electric operating companies, and Southern Power each engage in a long-term planning process to estimate the optimal mix and timing of new generation assets required to serve future load obligations. Southern Company Gas engages in a long-term planning process to estimate the optimal mix and timing of building new pipelines and storage facilities, replacing existing pipelines, rewatering storage facilities, and entering new markets and/or expanding in existing markets. These planning processes must look many years into the future in order to accommodate the long lead times associated with the permitting and construction of new generation and associated transmission facilities and natural gas distribution and storage facilities. Inherent risk exists in predicting demand this far into the future as these future loads are dependent on many uncertain factors, including economic conditions, customer usage patterns, efficiency programs, and customer technology adoption. Because regulators may not permit the traditional electric operating companies or Southern Company Gas' regulated operating companies to adjust rates to recover the costs of new generation and associated transmission assets and/or new pipelines and related infrastructure in a timely manner or at all, Southern Company and its subsidiaries may not be able to fully recover these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs and the recovery in customers' rates. In addition, under Southern Power's model of selling capacity and energy at negotiated market-based rates under long-term PPAs, Southern Power might not be able to fully execute its business plan if

market prices drop below original forecasts. Southern Power and/or the traditional electric operating companies may not be able to extend existing PPAs or find new buyers for existing generation assets as existing PPAs expire, or they may be forced to market these assets at prices lower than originally intended. These situations could have negative impacts on net income and cash flows for the affected traditional electric operating company, Southern Power, or Southern Company Gas, and for Southern Company.

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

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

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

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

As of December 31, 2016, Mississippi Power’s current liabilities exceeded current assets by approximately $371 million primarily due to $551 million in promissory notes to Southern Company which mature in December 2017, $35 million in senior notes which mature in November 2017, and $63 million in short-term debt. Mississippi Power expects the funds needed to satisfy the promissory notes to Southern Company will exceed amounts available from operating cash flows, lines of credit, and other external sources. Accordingly, Mississippi Power intends to satisfy these obligations through loans and/or equity contributions from Southern Company. Specifically, Mississippi Power has been informed by Southern Company that, in the event sufficient funds are not available from external sources, Southern Company intends to (i) extend the maturity of the $551 million in promissory notes and (ii) provide Mississippi Power with loans and/or equity contributions sufficient to fund the remaining indebtedness scheduled to mature and other cash needs over the next 12 months.

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

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

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

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

The financial condition of some insurance companies, the threat of terrorism, and natural disasters, among other things, could have disruptive effects on insurance markets. The availability of insurance covering risks that Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas, and their respective competitors typically insure against may decrease, and the insurance that Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas are able to obtain may have higher deductibles, higher premiums, and more restrictive policy terms. Further, the insurance policies maintained by Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas may not cover all of the potential exposures or the actual amount of loss incurred.

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

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

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

In addition, Southern Company Gas utilizes derivative instruments to lock in economic value in wholesale gas services, which may not qualify or are not designated as hedges for accounting purposes. The difference in accounting treatment for the underlying position and the financial instrument used to hedge the value of the contract can cause volatility in reported net income of Southern Company and Southern Company Gas while the positions are open due to mark-to-market accounting.

Future impairments of goodwill or long-lived assets could have a material adverse effect on Southern Company's and its subsidiaries' results of operations.

Goodwill is assessed for impairment at least annually and more frequently if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value and long-lived assets are assessed for impairment whenever events or circumstances indicate that an asset's carrying amount may not be recoverable. In connection with the completion of the Merger, the application of the acquisition method of accounting was pushed down to Southern Company Gas. The excess of the purchase price over the fair values of Southern Company Gas' assets and liabilities was recorded as goodwill. This resulted in a significant increase in the goodwill recorded on Southern Company's and Southern Company Gas' consolidated balance sheets. In addition, Southern Company and its subsidiaries have long-lived assets recorded on their balance sheets. To the extent the value of goodwill or long-lived assets become impaired, Southern Company, Southern Company Gas, Southern Power, and the traditional electric operating companies may be required to incur impairment charges that could have a material impact on their results of operations.

Item 1B. UNRESOLVED STAFF COMMENTS.

None.

Item 2. PROPERTIES

Electric

Electric Properties

The traditional electric operating companies, Southern Power, and SEGCO, at December 31, 2016, owned and/or operated 33 hydroelectric generating stations, 29 fossil fuel generating stations, three nuclear generating stations, 14 combined cycle/cogeneration stations, 33 solar facilities, seven wind facilities, one biomass facility, and one landfill gas facility. The amounts of capacity for each company, as of December 31, 2016, are shown in the table below.

Generating Station	Location	Nameplate Capacity (1)	
		(KWs)	
FOSSIL STEAM			
Gadsden	Gadsden, AL	120,000	(2)
Gorgas	Jasper, AL	1,021,250	
Barry	Mobile, AL	1,300,000	(2)
Greene County	Demopolis, AL	300,000	(3)
Gaston Unit 5	Wilsonville, AL	880,000	
Miller	Birmingham, AL	2,532,288	(4)
Alabama Power Total		6,153,538	
Bowen	Cartersville, GA	3,160,000	
Hammond	Rome, GA	800,000	
McIntosh	Effingham County, GA	163,117	
Scherer	Macon, GA	750,924	(5)
Wansley	Carrollton, GA	925,550	(6)
Yates	Newnan, GA	700,000	
Georgia Power Total		6,499,591	
Crist	Pensacola, FL	970,000	
Daniel	Pascagoula, MS	500,000	(7)
Scherer Unit 3	Macon, GA	204,500	(5)
Gulf Power Total		1,674,500	
Daniel	Pascagoula, MS	500,000	(7)
Greene County	Demopolis, AL	200,000	(3)
Watson	Gulfport, MS	862,000	(8)
Mississippi Power Total		1,562,000	
Gaston Units 1-4	Wilsonville, AL		
SEGCO Total		1,000,000	(9)
Total Fossil Steam		16,889,629	
IGCC			
Kemper County/Ratcliffe	Kemper County, MS		(10)
Mississippi Power Total		622,906	

Generating Station	Location	Nameplate Capacity (1)	
NUCLEAR STEAM			
Farley	Dothan, AL		
Alabama Power Total		1,720,000	
Hatch	Baxley, GA	899,612	(11)
Vogtle Units 1 and 2	Augusta, GA	1,060,240	(12)
Georgia Power Total		1,959,852	
Total Nuclear Steam		3,679,852	
COMBUSTION TURBINES			
Greene County	Demopolis, AL		
Alabama Power Total		720,000	
Boulevard	Savannah, GA	19,700	
McDonough Unit 3	Atlanta, GA	78,800	
McIntosh Units 1 through 8	Effingham County, GA	640,000	
McManus	Brunswick, GA	481,700	
Robins	Warner Robins, GA	158,400	
Wansley	Carrollton, GA	26,322	(6)
Wilson	Augusta, GA	354,100	
Georgia Power Total		1,759,022	
Lansing Smith Unit A	Panama City, FL	39,400	
Pea Ridge Units 1 through 3	Pea Ridge, FL	15,000	
Gulf Power Total		54,400	
Chevron Cogenerating Station	Pascagoula, MS	147,292	(13)
Sweatt	Meridian, MS	39,400	
Watson	Gulfport, MS	39,360	
Mississippi Power Total		226,052	
Addison	Thomaston, GA	668,800	
Cleveland County	Cleveland County, NC	720,000	
Dahlberg	Jackson County, GA	756,000	
Oleander	Cocoa, FL	791,301	
Rowan	Salisbury, NC	455,250	
Southern Power Total		3,391,351	
Gaston **(SEGCO)**	Wilsonville, AL	19,680	(9)
Total Combustion Turbines		6,170,505	
COGENERATION			
Washington County	Washington County, AL	123,428	
GE Plastics Project	Burkeville, AL	104,800	
Theodore	Theodore, AL	236,418	
Total Cogeneration		464,646	

Generating Station	Location	Nameplate Capacity (1)	
COMBINED CYCLE			
Barry	Mobile, AL		
Alabama Power Total		1,070,424	
McIntosh Units 10&11	Effingham County, GA	1,318,920	
McDonough-Atkinson Units 4 through 6	Atlanta, GA	2,520,000	
Georgia Power Total		3,838,920	
Smith	Lynn Haven, FL		
Gulf Power Total		545,500	
Daniel	Pascagoula, MS		
Mississippi Power Total		1,070,424	
Franklin	Smiths, AL	1,857,820	
Harris	Autaugaville, AL	1,318,920	
Mankato	Mankato, MN	375,000	
Rowan	Salisbury, NC	530,550	
Stanton Unit A	Orlando, FL	428,649	(14)
Wansley	Carrollton, GA	1,073,000	
Southern Power Total		5,583,939	
Total Combined Cycle		12,109,207	
HYDROELECTRIC FACILITIES			
Bankhead	Holt, AL	53,985	
Bouldin	Wetumpka, AL	225,000	
Harris	Wedowee, AL	132,000	
Henry	Ohatchee, AL	72,900	
Holt	Holt, AL	46,944	
Jordan	Wetumpka, AL	100,000	
Lay	Clanton, AL	177,000	
Lewis Smith	Jasper, AL	157,500	
Logan Martin	Vincent, AL	135,000	
Martin	Dadeville, AL	182,000	
Mitchell	Verbena, AL	170,000	
Thurlow	Tallassee, AL	81,000	
Weiss	Leesburg, AL	87,750	
Yates	Tallassee, AL	47,000	
Alabama Power Total		1,668,079	
Bartletts Ferry	Columbus, GA	173,000	
Goat Rock	Columbus, GA	38,600	
Lloyd Shoals	Jackson, GA	14,400	
Morgan Falls	Atlanta, GA	16,800	
North Highlands	Columbus, GA	29,600	
Oliver Dam	Columbus, GA	60,000	
Rocky Mountain	Rome, GA	215,256	(15)
Sinclair Dam	Milledgeville, GA	45,000	
Tallulah Falls	Clayton, GA	72,000	
Terrora	Clayton, GA	16,000	
Tugalo	Clayton, GA	45,000	
Wallace Dam	Eatonton, GA	321,300	
Yonah	Toccoa, GA	22,500	

Generating Station	Location	Nameplate Capacity (1)	
6 Other Plants	Various Georgia locations	18,080	
Georgia Power Total		1,087,536	
Total Hydroelectric Facilities		2,755,615	
RENEWABLE SOURCES:			
SOLAR FACILITIES			
Fort Benning	Columbus, GA	30,000	
Fort Gordon	Augusta, GA	30,000	
Fort Stewart	Fort Stewart, GA	30,000	
Kings Bay	Camden County, GA	30,000	
Dalton	Dalton, GA	6,305	
3 Other Plants	Various Georgia locations	2,789	
Georgia Power Total		129,094	
Adobe	Kern County, CA	20,000	
Apex	North Las Vegas, NV	20,000	
Boulder I	Clark County, NV	100,000	
Butler	Taylor County, GA	103,700	
Butler Solar Farm	Taylor County, GA	22,000	
Calipatria	Imperial County, CA	20,000	
Campo Verde	Imperial County, CA	147,420	
Cimarron	Springer, NM	30,640	
Decatur County	Decatur County, GA	20,000	
Decatur Parkway	Decatur County, GA	84,000	
Desert Stateline	San Bernadino County, CA	299,900	(16)
Garland	Kern County, CA	205,130	
Granville	Oxford, NC	2,500	
Henrietta	Kings County, CA	102,000	
Imperial Valley	Imperial County, CA	163,200	
Lost Hills - Blackwell	Kern County, CA	33,440	
Macho Springs	Luna County, NM	55,000	
Morelos del Sol	Kern County, CA	15,000	
North Star	Fresno County, CA	61,600	
Pawpaw	Taylor County, GA	30,480	
Roserock	Pecos County, TX	160,000	
Rutherford	Rutherford County, NC	74,800	
Sandhills	Taylor County, GA	146,890	
Spectrum	Clark County, NV	30,240	
Tranquillity	Fresno County, CA	205,300	
Southern Power Total		2,153,240	(17)
Total Solar		2,282,334	
WIND FACILITIES			
Grant Plains	Grant County, OK	147,200	
Grant Wind	Grant County, OK	151,800	
Kay Wind	Kay County, OK	299,000	
Passadumkeag	Penobscot County, ME	42,900	
Salt Fork	Donley & Gray Counties TX	174,000	
Tyler Bluff	Cooke County, TX	125,580	
Wake Wind	Crosby & Floyd Counties, TX	257,250	(18)

Generating Station	Location	Nameplate Capacity (1)
Southern Power Total		1,197,730
LANDFILL GAS FACILITY		
Perdido	Escambia County, FL	
Gulf Power Total		3,200
BIOMASS FACILITY		
Nacogdoches	Sacul, TX	
Southern Power Total		115,500
Total Generating Capacity		46,291,124

Notes:

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

(2) In April 2015, as part of its environmental compliance strategy, Alabama Power ceased using coal at Gadsden Steam Plant and at Plant Barry Units 1 and 2 (250 MWs), but such units will remain available with natural gas as the fuel source. Alabama Power retired Plant Barry Unit 3 (225 MWs) in August 2015 and it is no longer available for generation.

(3) Owned by Alabama Power and Mississippi Power as tenants in common in the proportions of 60% and 40%, respectively. In April 2016, Alabama Power and Mississippi Power ceased using coal and began operating Units 1 and 2 solely on natural gas in June 2016 and July 2016, respectively. See Note 3 to the financial statements of Southern Company, Alabama Power, and Mississippi Power under "Regulatory Matters – Alabama Power – Environmental Accounting Order," "Retail Regulatory Matters – Environmental Accounting Order," and "Retail Regulatory Matters – Environmental Compliance Overview Plan," respectively, in Item 8 herein.

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

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

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

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

(8) Mississippi Power ceased burning coal and other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and began operating those units solely on natural gas in April 2015. Mississippi Power retired Plant Sweatt Units 1 and 2 (80 MWs) on July 31, 2016.

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

(10) The capacity shown is the gross capacity using natural gas fuel without supplemental firing. The net capacity using lignite fuel with supplemental firing is expected to be 582 MWs. Mississippi Power placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service using natural gas in 2014 and expects to place the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, in service by mid-March 2017.

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

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

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

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

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

(16) 110 MWs were placed in service in the fourth quarter 2015 and 189 MWs were placed in service through July 2016, bringing the facility's total capacity to approximately 300 MWs.

(17) Southern Power total solar capacity shown is 100% of the nameplate capacity for each facility. When taking into consideration Southern Power's 90% equity interest in STR and various 66% and 51% equity interests in SRP's nine solar partnerships, Southern Power's equity portion of the total nameplate capacity from all solar facilities is 1,505 MWs. See Note 2 to the financial statements of Southern Power in Item 8 herein and Note 12 to the financial statements of Southern Company under "Southern Power" in Item 8 herein for additional information.

(18) Southern Power owns 90.1%.

Except as discussed below under "Titles to Property," the principal plants and other important units of the traditional electric operating companies, Southern Power, and SEGCO are owned in fee by the respective companies. It is the opinion of

management of each such company that its operating properties are adequately maintained and are substantially in good operating condition, and suitable for their intended purpose.

Mississippi Power owns a 79-mile length of 500-kilovolt transmission line which is leased to Entergy Gulf States Louisiana, LLC. The line, completed in 1984, extends from Plant Daniel to the Louisiana state line. Entergy Gulf States Louisiana, LLC is paying a use fee over a 40-year period covering all expenses and the amortization of the original $57 million cost of the line. At December 31, 2016, the unamortized portion of this cost was approximately $16 million.

In conjunction with the Kemper IGCC, Mississippi Power owns a lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site in Kemper County. The mine, operated by North American Coal Corporation, started commercial operation in 2013 with the capital cost of the mine and equipment totaling approximately $325 million as of December 31, 2016. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Lignite Mine and CO_2 Pipeline Facilities" of Mississippi Power in Item 7 herein and Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle – Lignite Mine and CO_2 Pipeline Facilities" in Item 8 herein for additional information on the lignite mine.

In 2016, the maximum demand on the traditional electric operating companies, Southern Power, and SEGCO was 35,781,000 KWs and occurred on July 25, 2016. The all-time maximum demand of 38,777,000 KWs on the traditional electric operating companies, Southern Power, and SEGCO occurred on August 22, 2007. These amounts exclude demand served by capacity retained by MEAG Power, OPC, and SEPA. The reserve margin for the traditional electric operating companies, Southern Power, and SEGCO in 2016 was 34.2%. See SELECTED FINANCIAL DATA in Item 6 herein for additional information.

Jointly-Owned Facilities

Alabama Power, Georgia Power, and Southern Power at December 31, 2016 had undivided interests in certain generating plants and other related facilities with non-affiliated parties. The percentages of ownership of the total plant or facility are as follows:

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

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

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

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

Titles to Property

The traditional electric operating companies', Southern Power's, and SEGCO's interests in the principal plants (other than certain pollution control facilities and the land on which five combustion turbine generators of Mississippi Power are located, which is held by easement) and other important units of the respective companies are owned in fee by such companies, subject only to the (1) liens pursuant to pollution control revenue bonds of Gulf Power on specific pollution control facilities at Plant Daniel, (2) liens pursuant to the assumption of debt obligations by Mississippi Power in connection with the acquisition of Plant Daniel Units 3 and 4, (3) liens associated with Georgia Power's reimbursement obligations to the DOE under its loan guarantee, which are secured by a first priority lien on (a) Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 and (b) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4, and (4) liens associated with two PPAs assumed as part of the acquisition of the Mankato project on October 26, 2016 by Southern Power Company. See Note 6 to the financial statements of Southern Company, Georgia Power, Gulf Power, Mississippi Power, and Southern Power under "Assets Subject to Lien," Note 6 to the financial statements of Southern Company and Georgia Power under "DOE Loan Guarantee Borrowings" and Note 6 to the financial statements of Southern Company and Mississippi Power under "Plant Daniel Revenue Bonds" in Item 8 herein for additional information. The traditional electric operating companies own the fee interests in certain of their principal plants as tenants in common. See "Jointly-Owned Facilities" herein for additional information. Properties such as electric transmission and distribution lines, steam heating mains, and gas pipelines are constructed principally on rights-of-way, which are maintained under franchise or are held by easement only. A substantial portion of lands submerged by reservoirs is held under flood right easements. In addition, certain of the renewable generating facilities occupy or use real property that is not owned, primarily through various leases, easements, rights-of-way, permits, or licenses from private landowners or governmental entities.

Natural Gas

Southern Company Gas considers its properties to be adequately maintained, substantially in good operating condition, and suitable for their intended purpose. The following provides the location and general character of the materially important properties that are used by the segments of Southern Company Gas. Substantially all of Nicor Gas' properties are subject to the lien of the indenture securing its first mortgage bonds. See Note 6 to the financial statements of Southern Company Gas under "Long-Term Debt – First Mortgage Bonds" in Item 8 herein for additional information.

Distribution and Transmission Mains – Southern Company Gas' distribution systems transport natural gas from its pipeline suppliers to customers in its service areas. These systems consist primarily of distribution and transmission mains, compressor stations, peak shaving/storage plants, service lines, meters, and regulators. At December 31, 2016, Southern Company Gas' gas distribution operations segment owned approximately 81,800 miles of underground distribution and transmission mains, which are located on easements or rights-of-way that generally provide for perpetual use.

Storage Assets – Gas Distribution Operations – Southern Company Gas owns and operates eight underground natural gas storage facilities in Illinois with a total inventory capacity of approximately 150 Bcf, approximately 135 Bcf of which can be cycled on an annual basis. This system is designed to meet about 50% of the estimated peak-day deliveries and approximately 40% of the normal winter deliveries in Illinois. This level of storage capability provides Nicor Gas with supply flexibility, improves the reliability of deliveries, and helps mitigate the risk associated with seasonal price movements.

Southern Company Gas also has five liquefied natural gas (LNG) plants located in Georgia, New Jersey, and Tennessee with total LNG storage capacity of approximately 7.6 Bcf. In addition, Southern Company Gas owns one propane storage facility in Virginia with storage capacity of approximately 0.3 Bcf. The LNG plants and propane storage facility are used by Southern Company Gas' gas distribution operations segment to supplement natural gas supply during peak usage periods.

Storage Assets – All Other – Southern Company Gas owns three high-deliverability natural gas storage and hub facilities that are operated by the gas midstream operations segment. Jefferson Island Storage & Hub, LLC operates a storage facility in Louisiana currently consisting of two salt dome gas storage caverns. Golden Triangle Storage, Inc. operates a storage facility in Texas consisting of two salt dome caverns. Central Valley Gas Storage, LLC operates a depleted field storage facility in California. In addition, Southern Company Gas has a LNG facility in Alabama that produces LNG for Pivotal LNG, Inc. to support its business of selling LNG as a substitute fuel in various markets.

Jointly-Owned Properties – Southern Company Gas' gas midstream operations segment has a 50% undivided ownership interest in a 115-mile pipeline facility being constructed in northwest Georgia. Southern Company Gas also has an agreement to lease its 50% undivided ownership in the pipeline facility once it is placed in service. See Note 4 to the financial statements of Southern Company and Southern Company Gas in Item 8 herein for additional information.

Item 3. LEGAL PROCEEDINGS

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

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

EXECUTIVE OFFICERS OF SOUTHERN COMPANY

(Identification of executive officers of Southern Company is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2016.

Thomas A. Fanning
Chairman, President, and Chief Executive Officer
Age 59
Elected in 2003. Chairman and Chief Executive Officer since December 2010 and President since August 2010.

Art P. Beattie
Executive Vice President and Chief Financial Officer
Age 62
Elected in 2010. Executive Vice President and Chief Financial Officer since August 2010.

W. Paul Bowers
Executive Vice President
Age 60
Elected in 2001. Executive Vice President since February 2008 and Chief Executive Officer, President, and Director of Georgia Power since January 2011. Chairman of Georgia Power's Board of Directors since May 2014.

S. W. Connally, Jr.
Chairman, President, and Chief Executive Officer of Gulf Power
Age 47
Elected in 2012. Elected Chairman in July 2015 and President, Chief Executive Officer, and Director of Gulf Power since July 2012. Previously served as Senior Vice President and Chief Production Officer of Georgia Power from August 2010 through June 2012.

Mark A. Crosswhite
Executive Vice President
Age 54
Elected in 2010. Executive Vice President since December 2010 and President, Chief Executive Officer, and Director of Alabama Power since March 2014. Chairman of Alabama Power's Board of Directors since May 2014. Previously served as Executive Vice President and Chief Operating Officer of Southern Company from July 2012 through February 2014 and President, Chief Executive Officer, and Director of Gulf Power from January 2011 through June 2012.

Andrew W. Evans
Executive Vice President
Age 50
Elected in July 2016. Executive Vice President since July 2016. President of Southern Company Gas since May 2015 and Chief Executive Officer and Chairman of Southern Company Gas' Board of Directors since January 2016. Previously served as Chief Operating Officer of Southern Company Gas from May 2015 through December 2015 and Executive Vice President and Chief Financial Officer of Southern Company Gas from May 2006 through May 2015.

Kimberly S. Greene
Executive Vice President
Age 50
Elected in 2013. Executive Vice President and Chief Operating Officer since March 2014. Director of Southern Company Gas since July 2016. Previously served as President and Chief Executive Officer of SCS from April 2013 to February 2014. Before rejoining Southern Company, Ms. Greene previously served at Tennessee Valley Authority as Executive Vice President and Chief Generation Officer from 2011 through April 2013 and Group President of Strategy and External Relations from 2010 through 2011.

James Y. Kerr II
Executive Vice President and General Counsel
Age 52
Elected in 2014. Also serves as Chief Compliance Officer. Before joining Southern Company, Mr. Kerr was a partner with McGuireWoods LLP and a senior advisor at McGuireWoods Consulting LLC from 2008 through February 2014.

Stephen E. Kuczynski
Chairman, President, and Chief Executive Officer of Southern Nuclear
Age 54
Elected in 2011. Chairman, President, and Chief Executive Officer of Southern Nuclear since July 2011.

Mark S. Lantrip
Executive Vice President
Age 62
Elected in 2014. Chairman, President, and Chief Executive Officer of SCS since March 2014. Previously served as Treasurer of Southern Company from October 2007 to February 2014 and Executive Vice President of SCS from November 2010 to March 2014.

Anthony L. Wilson
Chairman, President, and Chief Executive Officer of Mississippi Power
Age 52
Elected in 2015. President of Mississippi Power since October 2015 and Chief Executive Officer and Director since January 2016. Chairman of Mississippi Power's Board of Directors since August 2016. Previously served as Executive Vice President of Mississippi Power from May 2015 to October 2015 and Executive Vice President of Georgia Power from January 2012 to May 2015.

Christopher C. Womack
Executive Vice President
Age 58
Elected in 2008. Executive Vice President and President of External Affairs since January 2009.

The officers of Southern Company were elected at the first meeting of the directors following the last annual meeting of stockholders held on May 25, 2016, for a term of one year or until their successors are elected and have qualified, except for Mr. Andrew W. Evans, whose election as Executive Vice President was effective July 18, 2016.

EXECUTIVE OFFICERS OF ALABAMA POWER

(Identification of executive officers of Alabama Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2016.

Mark A. Crosswhite
Chairman, President, and Chief Executive Officer
Age 54
Elected in 2014. President, Chief Executive Officer, and Director since March 1, 2014. Chairman since May 2014. Previously served as Executive Vice President and Chief Operating Officer of Southern Company from July 2012 through February 2014 and President, Chief Executive Officer, and Director of Gulf Power from January 2011 through June 2012.

Greg J. Barker
Executive Vice President
Age 53
Elected in 2016. Executive Vice President for Customer Services since February 2016. Previously served as Senior Vice President of Marketing and Economic Development from April 2012 to February 2016 and Senior Vice President of Business Development and Customer Support from July 2010 to April 2012.

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer
Age 57
Elected in 2010. Executive Vice President, Chief Financial Officer, and Treasurer since August 2010.

Zeke W. Smith
Executive Vice President
Age 57
Elected in 2010. Executive Vice President of External Affairs since November 2010.

James P. Heilbron
Senior Vice President and Senior Production Officer
Age 45
Elected in 2013. Senior Vice President and Senior Production Officer since March 2013. Previously served as Senior Vice President and Senior Production Officer of Southern Power Company from July 2010 to February 2013.

The officers of Alabama Power were elected at the meeting of the directors held on April 22, 2016 for a term of one year or until their successors are elected and have qualified.

EXECUTIVE OFFICERS OF GEORGIA POWER

(Identification of executive officers of Georgia Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2016.

W. Paul Bowers
Chairman, President, and Chief Executive Officer
Age 60
Elected in 2010. Chief Executive Officer, President, and Director since December 2010 and Chief Operating Officer of Georgia Power from August 2010 to December 2010. Chairman of Georgia Power's Board of Directors since May 2014.

W. Craig Barrs (1)
Executive Vice President
Age 59
Elected in 2008. Executive Vice President of Customer Service and Operations since May 2015. Previously served as Executive Vice President of External Affairs from January 2010 to May 2015.

Pedro P. Cherry (1)
Executive Vice President
Age 45
Elected effective March 2017. Executive Vice President of Customer Service and Operations effective March 31, 2017. Senior Vice President since March 2015. Previously served as Vice President from January 2012 to March 2015.

W. Ron Hinson
Executive Vice President, Chief Financial Officer, and Treasurer
Age 60
Elected in 2013. Executive Vice President, Chief Financial Officer, and Treasurer since March 2013. Served as Corporate Secretary and Chief Compliance Officer from January 2016 through October 2016. Also, served as Comptroller from March 2013 until January 2014. Previously served as Comptroller and Chief Accounting Officer of Southern Company, as well as Senior Vice President and Comptroller of SCS from March 2006 to March 2013.

Christopher P. Cummiskey
Executive Vice President
Age 42
Elected in 2015. Executive Vice President of External Affairs since May 2015. Previously served as Chief Commercial Officer of Southern Power from October 2013 to May 2015 and Commissioner of the Georgia Department of Economic Development from January 2011 to October 2013.

Meredith M. Lackey
Senior Vice President, General Counsel, and Corporate Secretary
Age 42
Elected in November 2016. Senior Vice President, General Counsel, Corporate Secretary, and Chief Compliance Officer since November 2016. Previously served as Vice President, General Counsel, Chief Compliance Officer, and Corporate Secretary at Colonial Pipeline from January 2012 through November 2016.

Theodore J. McCullough
Senior Vice President and Senior Production Officer
Age 53
Elected in July 2016. Senior Vice President and Senior Production Officer since July 2016. Also has served as Senior Vice President of SCS since June 2010.

(1) On January 26, 2017, Mr. Barrs resigned the role of Executive Vice President, effective March 31, 2017. Also on January 26, 2017, Mr. Pedro P. Cherry was elected to the role of Executive Vice President, effective March 31, 2017.

The officers of Georgia Power were elected at the meeting of the directors held on May 18, 2016 for a term of one year or until their successors are elected and have qualified, except for Mr. McCullough, whose election as Senior Vice President was effective July 30, 2016, Ms. Lackey, whose election as Senior Vice President, General Counsel, and Corporate Secretary was effective November 1, 2016, and Mr. Cherry, whose election as Executive Vice President is effective March 31, 2017.

EXECUTIVE OFFICERS OF MISSISSIPPI POWER

(Identification of executive officers of Mississippi Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2016.

Anthony L. Wilson
Chairman, President, and Chief Executive Officer
Age 52
Elected in 2015. President since October 2015 and Chief Executive Officer and Director since January 2016. Chairman of Mississippi Power's Board since August 2016. Previously served as Executive Vice President from May 2015 to October 2015 and Executive Vice President of Georgia Power from January 2012 to May 2015.

John W. Atherton
Vice President
Age 56
Elected in 2004. Vice President of Corporate Services and Community Relations since October 2012. Previously served as Vice President of External Affairs from January 2005 until October 2012.

A. Nicole Faulk
Vice President
Age 43
Elected in 2015. Vice President of Customer Services Organization effective April 2015. Previously served as Region Vice President for the West Region of Georgia Power from March 2015 through April 2015 and Region Manager for the Metro West Region of Georgia Power from December 2011 to March 2015.

Moses H. Feagin
Vice President, Treasurer, and Chief Financial Officer
Age 52
Elected in 2010. Vice President, Treasurer, and Chief Financial Officer since August 2010.

R. Allen Reaves, Jr.
Vice President
Age 57
Elected in 2010. Vice President and Senior Production Officer since August 2010.

Billy F. Thornton
Vice President
Age 56
Elected in 2012. Vice President of External Affairs since October 2012. Previously served as Director of External Affairs from October 2011 until October 2012.

Emile J. Troxclair, III
Vice President
Age 59
Elected in 2014. Vice President of Kemper Development since January 2015. Previously served as Vice President of Gasification for Lummus Technology Inc. from May 2013 through April 2014, Manager of E-Gas Technology for Phillips 66 from 2012 to May 2013, and Manager of E-Gas Technology for ConocoPhillips from 2003 to 2012.

The officers of Mississippi Power were elected at the meeting of the directors held on April 26, 2016 for a term of one year or until their successors are elected and have qualified.

PART II

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

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

	High	Low
2016		
First Quarter	$ 51.73	$ 46.00
Second Quarter	53.64	47.62
Third Quarter	54.64	50.00
Fourth Quarter	52.23	46.20
2015		
First Quarter	$ 53.16	$ 43.55
Second Quarter	45.44	41.40
Third Quarter	46.84	41.81
Fourth Quarter	47.50	43.38

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

(a)(2) Number of Southern Company's common stockholders of record at January 31, 2017: 125,827

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

(a)(3) Dividends on each registrant's common stock are payable at the discretion of their respective board of directors. The dividends on common stock declared by Southern Company and the traditional electric operating companies (other than Mississippi Power) to their stockholder(s) for the past two years are set forth below. No dividends were declared by Mississippi Power on its common stock in 2015 or 2016.

Registrant	Quarter	2016	2015
		(in thousands)	
Southern Company	First	$ 496,718	$ 478,454
	Second	526,267	493,161
	Third	529,876	493,382
	Fourth	551,110	493,884
Alabama Power	First	191,206	142,820
	Second	191,206	142,820
	Third	191,206	142,820
	Fourth	191,206	142,820
Georgia Power	First	326,269	258,570
	Second	326,269	258,870
	Third	326,269	258,870
	Fourth	326,269	258,870
Gulf Power	First	30,017	32,540
	Second	30,017	32,540
	Third	30,017	32,540
	Fourth	30,017	32,540

In 2016 and 2015, Southern Power Company paid dividends to Southern Company as follows:

Registrant	Quarter	2016	2015
		(in thousands)	
Southern Power Company	First	$ 68,082	$ 32,640
	Second	68,082	32,640
	Third	68,082	32,640
	Fourth	68,082	32,640

Southern Company Gas paid dividends to Southern Company in the amount of $62,750,000 in each of the third and fourth quarters 2016.

The dividend paid per share of Southern Company's common stock was 54.25¢ for the first quarter 2016 and 56.00¢ each for the second, third, and fourth quarters of 2016. In 2015, Southern Company paid a dividend per share of 52.50¢ for the first quarter and 54.25¢ each for the second, third, and fourth quarters.

The traditional electric operating companies and Southern Power Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital. The authority of the natural gas distribution utilities to pay dividends to Southern Company Gas is subject to regulation. By regulation, Nicor Gas is restricted, to the extent of its retained earnings balance, in the amount it can dividend or loan to affiliates. Additionally, Elizabethtown Gas is restricted by its policy, as established by the New Jersey Board of Public Utilities, to 70% of its quarterly net income it can dividend to Southern Company Gas.

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

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

(b) Use of Proceeds

Not applicable.

(c) Issuer Purchases of Equity Securities

None.

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

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Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of each of the registrants in Item 7 herein and Note 1 of each of the registrant's financial statements under "Financial Instruments" in Item 8 herein. See also Note 10 to the financial statements of Southern Company, Alabama Power, and Georgia Power, Note 9 to the financial statements of Gulf Power, Mississippi Power, and Southern Company Gas, and Note 8 to the financial statements of Southern Power in Item 8 herein.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

None.

Item 9A. CONTROLS AND PROCEDURES

Disclosure Controls And Procedures.

As of the end of the period covered by this Annual Report on Form 10-K, Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and Southern Company Gas conducted separate evaluations under the supervision and with the participation of each company's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended). Based upon these evaluations, the Chief Executive Officer and the Chief Financial Officer, in each case, concluded that the disclosure controls and procedures are effective.

Internal Control Over Financial Reporting.

(a) Management's Annual Report on Internal Control Over Financial Reporting.

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(b) Attestation Report of the Registered Public Accounting Firm.

The report of Deloitte & Touche LLP, Southern Company's independent registered public accounting firm, regarding Southern Company's Internal Control over Financial Reporting is included on page II-9 of this Form 10-K. This report is not applicable to Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and Southern Company Gas as these companies are not accelerated filers or large accelerated filers.

(c) Changes in internal control over financial reporting.

Other than the changes resulting from the Merger discussed below, there have been no changes in Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, Southern Power's, or Southern Company Gas' internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended) during the fourth quarter 2016 that have materially affected or are reasonably likely to materially affect Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, Southern Power's, or Southern Company Gas' internal control over financial reporting.

Southern Company completed the Merger on July 1, 2016 with Southern Company Gas surviving the Merger as a wholly-owned, direct subsidiary of Southern Company. Southern Company has completed an internal controls review during the fourth quarter 2016 pursuant to Section 404 of the Sarbanes-Oxley Act of 2002.

Item 9B. OTHER INFORMATION

None.

THE SOUTHERN COMPANY
AND SUBSIDIARY COMPANIES

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Southern Company and Subsidiary Companies 2016 Annual Report

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

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

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of Southern Company's financial statements, has issued an attestation report on the effectiveness of Southern Company's internal control over financial reporting as of December 31, 2016 . Deloitte & Touche LLP's report on Southern Company's internal control over financial reporting is included herein.

/s/ Thomas A. Fanning
Thomas A. Fanning
Chairman, President, and Chief Executive Officer

/s/ Art P. Beattie
Art P. Beattie
Executive Vice President and Chief Financial Officer

February 21, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
The Southern Company

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of The Southern Company and Subsidiary Companies (the Company) as of December 31, 2016 and 2015 , and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2016 . We also have audited the Company's internal control over financial reporting as of December 31, 2016 , based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting (page II-8). Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements (pages II-59 to II-147) referred to above present fairly, in all material respects, the financial position of Southern Company and Subsidiary Companies as of December 31, 2016 and 2015 , and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 , in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016 , based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 21, 2017

DEFINITIONS

Term	**Meaning**
2012 MPSC CPCN Order	A detailed order issued by the Mississippi PSC in April 2012 confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing acquisition, construction, and operation of the Kemper IGCC
2013 ARP	Alternative Rate Plan approved by the Georgia PSC in 2013 for Georgia Power for the years 2014 through 2016 and subsequently extended through 2019
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ARO	Asset retirement obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Atlanta Gas Light	Atlanta Gas Light Company, a wholly-owned subsidiary of Southern Company Gas
Baseload Act	State of Mississippi legislation designed to enhance the Mississippi PSC's authority to facilitate development and construction of baseload generation in the State of Mississippi
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
COD	Commercial operation date
CPCN	Certificate of public convenience and necessity
CWIP	Construction work in progress
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FFB	Federal Financing Bank
GAAP	U.S. generally accepted accounting principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IGCC	Integrated coal gasification combined cycle
IRS	Internal Revenue Service
ITC	Investment tax credit
Kemper IGCC	IGCC facility under construction by Mississippi Power in Kemper County, Mississippi
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
Merger	The merger, effective July 1, 2016, of a wholly-owned, direct subsidiary of Southern Company with and into Southern Company Gas, with Southern Company Gas continuing as the surviving corporation
Mirror CWIP	A regulatory liability used by Mississippi Power to record customer refunds resulting from a 2015 Mississippi PSC order
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MPUS	Mississippi Public Utilities Staff
MW	Megawatt
natural gas distribution utilities	Southern Company Gas' seven natural gas distribution utilities (Nicor Gas, Atlanta Gas Light, Virginia Natural Gas, Inc., Elizabethtown Gas, Florida City Gas, Chattanooga Gas Company, and Elkton Gas)

DEFINITIONS
(continued)

Term	Meaning
NCCR	Georgia Power's Nuclear Construction Cost Recovery
NDR	Alabama Power's Natural Disaster Reserve
Nicor Gas	Northern Illinois Gas Company, a wholly-owned subsidiary of Southern Company Gas
NRC	U.S. Nuclear Regulatory Commission
OCI	Other comprehensive income
Plant Vogtle Units 3 and 4	Two new nuclear generating units under construction at Georgia Power's Plant Vogtle
PowerSecure	PowerSecure, Inc.
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 agreements and contracts for differences that provide the owner of a renewable facility a certain fixed price for the electricity sold to the grid
PSC	Public Service Commission
PTC	Production tax credit
Rate CNP	Alabama Power's Rate Certificated New Plant
Rate CNP Compliance	Alabama Power's Rate Certificated New Plant Compliance
Rate CNP PPA	Alabama Power's Rate Certificated New Plant Power Purchase Agreement
Rate ECR	Alabama Power's Rate Energy Cost Recovery
Rate NDR	Alabama Power's Rate Natural Disaster Reserve
Rate RSE	Alabama Power's Rate Stabilization and Equalization plan
ROE	Return on equity
S&P	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
SMEPA	South Mississippi Electric Power Association (now known as Cooperative Energy)
Southern Company Gas	Southern Company Gas (formerly known as AGL Resources Inc.) and its subsidiaries
Southern Company Gas Capital	Southern Company Gas Capital Corporation (formerly known as AGL Capital Corporation), a 100%-owned subsidiary of Southern Company Gas
Southern Company system	The Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SEGCO, Southern Nuclear, SCS, Southern LINC, PowerSecure (as of May 9, 2016), and other subsidiaries
Southern LINC	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional electric operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power
Westinghouse	Westinghouse Electric Company LLC

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Southern Company and Subsidiary Companies 2016 Annual Report

OVERVIEW

Business Activities

The Southern Company (Southern Company or the Company) is a holding company that owns all of the common stock of the traditional electric operating companies and the parent entities of Southern Power and Southern Company Gas and owns other direct and indirect subsidiaries. The primary business of the Southern Company system is electricity sales by the traditional electric operating companies and Southern Power and, following the closing of the Merger on July 1, 2016, the distribution of natural gas by Southern Company Gas. The four traditional electric operating companies are vertically integrated utilities providing electric service in four Southeastern states. Southern Power 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 the natural gas distribution utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations.

Many factors affect the opportunities, challenges, and risks of the Southern Company system's electricity and natural gas businesses. These factors include the ability to maintain constructive regulatory environments, to maintain and grow 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, restoration following major storms, and capital expenditures, including constructing new electric generating plants, expanding the electric transmission and distribution systems, and updating and expanding the natural gas distribution systems.

Construction continues on Plant Vogtle Units 3 and 4 (45.7% ownership interest by Georgia Power in the two units, each with approximately 1,100 MWs) and Mississippi Power's 582 -MW Kemper IGCC. See Note 3 to the financial statements under " Regulatory Matters – Georgia Power – Nuclear Construction " and " Integrated Coal Gasification Combined Cycle " for additional information.

The traditional electric operating companies and natural gas distribution utilities have various regulatory mechanisms that operate to address cost recovery. Effectively operating pursuant to these regulatory mechanisms and appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Southern Company system for the foreseeable future. See Note 3 to the financial statements under " Regulatory Matters " and " Integrated Coal Gasification Combined Cycle " for additional information.

Another major factor affecting the Southern Company system's businesses is the profitability of the competitive market-based wholesale generating business. Southern Power's strategy is to construct, acquire, own, manage, and sell power generation assets, including renewable energy projects, and to enter into PPAs primarily with investor-owned utilities, independent power producers, municipalities, and other load-serving entities.

Southern Company's other business activities include providing energy technologies and services to electric utilities and large industrial, commercial, institutional, and municipal customers. Customer solutions include distributed generation systems, utility infrastructure solutions, and energy efficiency products and services. Other business activities also include investments in telecommunications, leveraged lease projects, and gas storage facilities. Management continues to evaluate the contribution of each of these activities to total shareholder return and may pursue acquisitions, dispositions, and other strategic ventures or investments accordingly.

In striving to achieve attractive risk-adjusted returns while providing cost-effective energy to more than nine million electric and gas utility customers, the Southern Company system continues to focus on several key performance indicators. These indicators include, but are not limited to, customer satisfaction, plant availability, electric and natural gas system reliability, execution of major construction projects, and earnings per share (EPS). Southern Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the results of the Southern Company system.

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

Merger with Southern Company Gas

On July 1, 2016, Southern Company completed the Merger for a total purchase price of approximately $8.0 billion and Southern Company Gas became a wholly-owned, direct subsidiary of Southern Company.

Prior to the completion of the Merger, Southern Company and Southern Company Gas operated as separate companies. The discussion and analysis of results of operations and financial condition set forth herein includes Southern Company Gas' results of operations since July 1, 2016 and financial condition as of December 31, 2016. See Note 12 to the financial statements under " Southern Company – Merger with Southern Company Gas " for additional information regarding the Merger.

During 2016 and 2015, the Company recorded in its statements of income costs associated with the Merger of approximately $111 million and $41 million , respectively, of which $80 million and $27 million is included in operating expenses and $31 million and $14 million is included in other income and (expense), respectively. These costs include external transaction costs for financing, legal, and consulting services, as well as customer rate credits and additional compensation-related expenses.

Earnings

Consolidated net income attributable to Southern Company was $2.4 billion in 2016, an increase of $81 million , or 3.4% , from the prior year. Consolidated net income increased by $114 million as a result of earnings from Southern Company Gas, which was acquired on July 1, 2016. Also contributing to the increase were higher retail electric revenues resulting from non-fuel retail rate increases and warmer weather, primarily in the third quarter 2016, as well as the 2015 correction of a Georgia Power billing error, partially offset by accruals in 2016 for expected refunds at Alabama Power and Georgia Power. Additionally, the increase was due to increases in income tax benefits and renewable energy sales at Southern Power. These increases were partially offset by higher interest expense, non-fuel operations and maintenance expenses, depreciation and amortization, lower wholesale capacity revenues, and higher estimated losses associated with the Kemper IGCC. See Note 12 to the financial statements under " Southern Company – Merger with Southern Company Gas " for additional information regarding the Merger.

Consolidated net income attributable to Southern Company was $2.4 billion in 2015, an increase of $404 million , or 20.6% , from the prior year. The increase was primarily related to lower pre-tax charges of $365 million ($226 million after tax) recorded in 2015 compared to pre-tax charges of $868 million ($536 million after tax) recorded in 2014 for revisions of the estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC and an increase in retail base rates. The increases were partially offset by increases in non-fuel operations and maintenance expenses and depreciation and amortization.

Basic EPS was $2.57 in 2016, $2.60 in 2015, and $2.19 in 2014. Diluted EPS, which factors in additional shares related to stock-based compensation, was $2.55 in 2016, $2.59 in 2015, and $2.18 in 2014. EPS for 2016 was negatively impacted by $0.12 per share as a result of an increase in the average shares outstanding. See FINANCIAL CONDITION AND LIQUIDITY – " Financing Activities " herein for additional information.

Dividends

Southern Company has paid dividends on its common stock since 1948. Dividends paid per share of common stock were $2.2225 in 2016 , $2.1525 in 2015 , and $2.0825 in 2014 . In January 2017 , Southern Company declared a quarterly dividend of 56 cents per share. This is the 277th consecutive quarter that Southern Company has paid a dividend equal to or higher than the previous quarter. For 2016 , the dividend payout ratio was 86% .

RESULTS OF OPERATIONS

Discussion of the results of operations is divided into three parts – the Southern Company system's primary business of electricity sales, its gas business, and its other business activities.

	Amount		
	2016	2015	2014
		(in millions)	
Electricity business	**$ 2,571**	$ 2,401	$ 1,969
Gas business	**114**	—	—
Other business activities	**(237)**	(34)	(6)
Net Income	**$ 2,448**	$ 2,367	$ 1,963

Electricity Business

Southern Company's electric utilities generate and sell electricity to retail and wholesale customers primarily in the Southeast.

A condensed statement of income for the electricity business follows:

	Amount	Increase (Decrease) from Prior Year	
	2016	**2016**	2015
		(in millions)	
Electric operating revenues	**$ 17,941**	**$ 499**	$ (964)
Fuel	**4,361**	**(389)**	(1,255)
Purchased power	**750**	**105**	(27)
Cost of other sales	**58**	**58**	—
Other operations and maintenance	**4,523**	**231**	33
Depreciation and amortization	**2,233**	**213**	91
Taxes other than income taxes	**1,039**	**44**	16
Estimated loss on Kemper IGCC	**428**	**63**	(503)
Total electric operating expenses	**13,392**	**325**	(1,645)
Operating income	**4,549**	**174**	681
Allowance for equity funds used during construction	**200**	**(26)**	(19)
Interest expense, net of amounts capitalized	**931**	**157**	(20)
Other income (expense), net	**(75)**	**(43)**	23
Income taxes	**1,091**	**(235)**	273
Net income	**2,652**	**183**	432
Less:			
Dividends on preferred and preference stock of subsidiaries	**45**	**(9)**	(14)
Net income attributable to noncontrolling interests	**36**	**22**	14
Net Income Attributable to Southern Company	**$ 2,571**	**$ 170**	$ 432

Electric Operating Revenues

Electric operating revenues for 2016 were $17.9 billion , reflecting a $499 million increase from 2015. Details of electric operating revenues were as follows:

	Amount	
	2016	2015
	(in millions)	
Retail electric — prior year	**$ 14,987**	$ 15,550
Estimated change resulting from —		
Rates and pricing	**427**	375
Sales growth (decline)	**(35)**	50
Weather	**153**	(59)
Fuel and other cost recovery	**(298)**	(929)
Retail electric — current year	**15,234**	14,987
Wholesale electric revenues	**1,926**	1,798
Other electric revenues	**698**	657
Other revenues	**83**	—
Electric operating revenues	**$ 17,941**	$ 17,442
Percent change	**2.9%**	(5.2)%

Retail electric revenues increased $247 million , or 1.6% , in 2016 as compared to the prior year. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing in 2016 was primarily due to increases in base tariffs at Georgia Power under the 2013 ARP and the NCCR tariff and increased revenues at Alabama Power under Rate CNP Compliance, all effective January 1, 2016. Also contributing to the increase in rates and pricing for 2016 was the 2015 correction of an error affecting billings since 2013 to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing at Georgia Power and the implementation of rates at Mississippi Power for certain Kemper IGCC in-service assets, effective September 2015. These increases were partially offset by accruals in 2016 for expected refunds at Alabama Power and Georgia Power.

Retail electric revenues decreased $563 million , or 3.6% , in 2015 as compared to the prior year. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing in 2015 was primarily due to increased revenues at Alabama Power, associated with an increase in rates under Rate RSE, and at Georgia Power, related to increases in base tariffs under the 2013 ARP and the NCCR tariff, all effective January 1, 2015, as well as higher contributions from variable demand-driven pricing from commercial and industrial customers. The increase in rates and pricing was also due to the implementation of rates at Mississippi Power for certain Kemper IGCC in-service assets, effective September 2015. The increase was partially offset by the 2015 correction of an error affecting billings since 2013 to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing at Georgia Power.

See Note 3 to the financial statements under " Regulatory Matters – Alabama Power – Rate RSE " and " – Rate CNP Compliance " and " – Georgia Power – Rate Plans " and " – Nuclear Construction " and " Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs " and Note 1 to the financial statements under "General" for additional information. Also see "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

Electric rates for the traditional electric operating companies include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the energy component of PPA costs, and do not affect net income. The traditional electric operating companies each have one or more regulatory mechanisms to recover other costs such as environmental and other compliance costs, storm damage, new plants, and PPA capacity costs.

Wholesale electric revenues consist of PPAs primarily with investor-owned utilities and electric cooperatives and short-term opportunity sales. Wholesale electric revenues from PPAs (other than solar and wind PPAs) have both capacity and energy components. Capacity revenues generally represent the greatest contribution to net income and are designed to provide recovery of fixed costs plus a return on investment. Energy revenues will vary depending on fuel prices, the market prices of wholesale energy compared to the Southern Company system's generation, demand for energy within the Southern Company system's

electric service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Electricity sales from solar and wind PPAs do not have a capacity charge and customers either purchase the energy output of a dedicated renewable facility through an energy charge or through a fixed price for electricity. As a result, the Company's ability to recover fixed and variable operations and maintenance expenses is dependent upon the level of energy generated from these facilities, which can be impacted by weather conditions, equipment performance, and other factors. Wholesale electric revenues at Mississippi Power include FERC-regulated municipal and rural association sales as well as market-based sales. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Southern Company system's variable cost to produce the energy.

Wholesale electric revenues from power sales were as follows:

	2016	2015	2014
		(in millions)	
Capacity and other	**$ 771**	$ 875	$ 974
Energy	**1,155**	923	1,210
Total	**$ 1,926**	$ 1,798	$ 2,184

In 2016, wholesale revenues increased $128 million , or 7.1% , as compared to the prior year due to a $232 million increase in energy revenues, offset by a $104 million decrease in capacity revenues. The increase in energy revenues was primarily due to an increase in short-term sales and renewable energy sales at Southern Power, partially offset by lower fuel prices. The decrease in capacity revenues was primarily due to the expiration of wholesale contracts at Georgia Power and Gulf Power, the elimination in consolidation of a Southern Power PPA that was remarketed from a third party to Georgia Power in January 2016, and unit retirements at Georgia Power, partially offset by an increase due to a new wholesale contract at Alabama Power in the first quarter 2016.

In 2015, wholesale revenues decreased $386 million , or 17.7% , as compared to the prior year due to a $287 million decrease in energy revenues and a $99 million decrease in capacity revenues. The decreases in energy revenues were primarily related to lower fuel costs and lower customer demand due to milder weather as compared to the prior year, partially offset by increases in energy revenues from new solar and wind PPAs at Southern Power. The decreases in capacity revenues were primarily due to the expiration of wholesale contracts in December 2014 at Georgia Power, unit retirements at Georgia Power, and PPA expirations at Southern Power.

See FUTURE EARNINGS POTENTIAL – " Regulatory Matters – Gulf Power " for information regarding the expiration of long-term sales agreements at Gulf Power for Plant Scherer Unit 3, which will impact future wholesale earnings, and Gulf Power's request to rededicate its ownership interest in Scherer Unit 3 to the retail jurisdiction.

Other Electric Revenues

Other electric revenues increased $41 million , or 6.2% , and decreased $15 million , or 2.2% , in 2016 and 2015, respectively, as compared to the prior years. The 2016 increase was primarily due to a $14 million increase in customer temporary facilities services revenues and a $12 million increase in outdoor lighting revenues at Georgia Power. The 2015 decrease was primarily due to a $16 million decrease in transmission revenues at Georgia Power primarily as a result of a contract that expired in December 2014 and a $13 million decrease in co-generation steam revenues at Alabama Power, partially offset by an $11 million increase in outdoor lighting revenues at Georgia Power.

Energy Sales

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

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2016	**2016**	2015	**2016** (*)	2015 (*)
	(in billions)				
Residential	**53.3**	**2.3 %**	(2.3)%	**0.2 %**	0.4 %
Commercial	**53.7**	**0.4**	0.5	**(1.0)**	0.9
Industrial	**52.8**	**(2.1)**	(0.4)	**(2.2)**	(0.3)
Other	**0.9**	**(1.7)**	(1.4)	**(1.7)**	(1.3)
Total retail	**160.7**	**0.2**	(0.7)	**(1.0)%**	0.3 %
Wholesale	**34.9**	**14.4**	(7.0)		
Total energy sales	**195.6**	**2.4 %**	(1.8)%		

(*) In the first quarter 2015, Mississippi Power updated the methodology to estimate the unbilled revenue allocation among customer classes. This change did not have a significant impact on net income. The KWH sales variances in the above table reflect an adjustment to the estimated allocation of Mississippi Power's unbilled 2014 and first quarter 2015 KWH sales among customer classes that is consistent with the actual allocation in 2015 and 2016, respectively. Without this adjustment, 2016 weather-adjusted commercial sales decreased 0.9% and industrial KWH sales decreased 2.1% as compared to 2015. Without this adjustment, 2015 weather-adjusted commercial sales increased 0.8% and industrial KWH sales decreased 0.4% as compared to 2014.

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales increased 261 million KWHs in 2016 as compared to the prior year. This increase was primarily due to warmer weather in the third quarter 2016 as compared to the corresponding period in 2015 and customer growth, partially offset by decreased customer usage. The decrease in industrial KWH energy sales was primarily due to decreased sales in the primary metals, chemicals, paper, pipeline, and stone, clay, and glass sectors. A strong dollar, low oil prices, and weak global economic conditions constrained growth in the industrial sector in 2016. Weather-adjusted commercial KWH sales decreased primarily due to decreased customer usage resulting from an increase in electronic commerce transactions and energy saving initiatives, partially offset by customer growth. Weather-adjusted residential KWH sales increased primarily due to customer growth, partially offset by decreased customer usage primarily resulting from an increase in multi-family housing and efficiency improvements in residential appliances and lighting. Household income, one of the primary drivers of residential customer usage, had modest growth in 2016.

Retail energy sales decreased 1.2 billion KWHs in 2015 as compared to the prior year. This decrease was primarily the result of milder weather in the first and fourth quarters of 2015 as compared to the corresponding periods in 2014 and decreased customer usage, partially offset by customer growth. Weather-adjusted commercial KWH sales increased primarily due to customer growth and increased customer usage. Weather-adjusted residential KWH sales increased primarily due to customer growth, partially offset by decreased customer usage. Household income, one of the primary drivers of residential customer usage, had modest growth in 2015. The decrease in industrial KWH energy sales was primarily due to decreased sales in the primary metals, chemicals, and paper sectors, partially offset by increased sales in the transportation, stone, clay, and glass, pipeline, lumber, and petroleum sectors. A strong dollar, low oil prices, and weak global economic conditions constrained growth in the industrial sector in 2015.

See "Electric Operating Revenues" above for a discussion of significant changes in wholesale revenues related to changes in price and KWH sales.

Other Revenues

Other revenues increased $83 million in 2016 as compared to the prior year. The 2016 increase was primarily due to revenues from certain non-regulated sales of products and services by the traditional electric operating companies that were reclassified as other revenues for consistency of presentation on a consolidated basis following the PowerSecure acquisition. In prior periods, these revenues were included in other income (expense), net.

Fuel and Purchased Power Expenses

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

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

	2016	2015	2014
Total generation *(in billions of KWHs)*	**188**	187	191
Total purchased power *(in billions of KWHs)*	**16**	13	12
Sources of generation *(percent)* —			
Coal	**33**	34	42
Nuclear	**16**	16	16
Gas	**46**	46	39
Hydro	**2**	3	3
Other Renewables	**3**	1	—
Cost of fuel, generated *(in cents per net KWH)* —			
Coal	**3.04**	3.55	3.81
Nuclear	**0.81**	0.79	0.87
Gas	**2.48**	2.60	3.63
Average cost of fuel, generated *(in cents per net KWH)*	**2.40**	2.64	3.25
Average cost of purchased power *(in cents per net KWH)* (*)	**5.43**	6.11	7.13

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

In 2016, total fuel and purchased power expenses were $5.1 billion , a decrease of $284 million , or 5.3% , as compared to the prior year. The decrease was primarily the result of a $518 million decrease in the average cost of fuel and purchased power primarily due to lower coal and natural gas prices, partially offset by a $234 million increase in the volume of KWHs generated and purchased.

In 2015, total fuel and purchased power expenses were $5.4 billion , a decrease of $1.3 billion , or 19.2% , as compared to the prior year. The decrease was primarily the result of a $1.1 billion decrease in the average cost of fuel and purchased power primarily due to lower coal and natural gas prices and a $137 million net decrease in the volume of KWHs generated and purchased due to milder weather in the first and fourth quarters of 2015.

Fuel and purchased power energy transactions at the traditional electric operating companies are generally offset by fuel revenues and do not have a significant impact on net income. See FUTURE EARNINGS POTENTIAL – " Regulatory Matters – Fuel Cost Recovery " herein for additional information. Fuel expenses incurred under Southern Power's PPAs are generally the responsibility of the counterparties and do not significantly impact net income.

Fuel

In 2016, fuel expense was $4.4 billion , a decrease of $389 million , or 8.2% , as compared to the prior year. The decrease was primarily due to a 14.4% decrease in the average cost of coal per KWH generated, a 4.6% decrease in the average cost of natural gas per KWH generated, and a 2.7% decrease in the volume of KWHs generated by coal, partially offset by a 3.5% increase in the volume of KWHs generated by natural gas.

In 2015, fuel expense was $4.8 billion , a decrease of $1.3 billion , or 20.9% , as compared to the prior year. The decrease was primarily due to a 28.4% decrease in the average cost of natural gas per KWH generated, a 19.2% decrease in the volume of KWHs generated by coal, and a 6.8% decrease in the average cost of coal per KWH generated, partially offset by a 15.9% increase in the volume of KWHs generated by natural gas.

Purchased Power

In 2016, purchased power expense was $750 million , an increase of $105 million , or 16.3% , as compared to the prior year. The increase was primarily due to a 28.8% increase in the volume of KWHs purchased, partially offset by an 11.1% decrease in the average cost per KWH purchased primarily as a result of lower natural gas prices.

In 2015, purchased power expense was $645 million , a decrease of $27 million , or 4.0% , as compared to the prior year. The decrease was primarily due to a 14.3% decrease in the average cost per KWH purchased primarily as a result of lower natural gas prices, partially offset by a 5.3% increase in the volume of KWHs purchased.

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

Cost of Other Sales

Cost of other sales were $58 million in 2016. These costs were related to certain non-regulated sales of products and services by the traditional electric operating companies that were reclassified as cost of other sales for consistency of presentation on a consolidated basis following the PowerSecure acquisition. In prior periods, these costs were included in other income (expense), net.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses increased $231 million , or 5.4% , in 2016 as compared to the prior year. The increase was primarily related to a $76 million increase in transmission and distribution expenses primarily related to overhead line maintenance, a $37 million decrease in gains from sales of assets at Georgia Power, a $36 million charge in connection with cost containment activities at Georgia Power, and a $35 million increase at Southern Power associated with new solar and wind facilities placed in service in 2015 and 2016. Additionally, the increase was due to a $19 million increase in generation expenses primarily related to environmental costs, a $19 million increase in business development and support expenses at Southern Power, and an $11 million increase in scheduled outage and maintenance costs at generation facilities, partially offset by a $41 million net decrease in employee compensation and benefits, including pension costs.

Other operations and maintenance expenses increased $33 million , or 0.8% , in 2015 as compared to the prior year. The increase was primarily related to an $84 million increase in employee compensation and benefits including pension costs, a $62 million increase in generation expenses primarily related to environmental costs, and an $11 million increase in customer accounts, service, and sales costs primarily related to customer incentive and demand-side management programs, partially offset by a $99 million decrease in transmission and distribution costs primarily related to reduced overhead line maintenance and gains from sales of transmission assets and a $32 million decrease in scheduled outage and maintenance costs at generation facilities.

Production expenses and transmission and distribution expenses fluctuate from year to year due to variations in outage and maintenance schedules and normal changes in the cost of labor and materials.

Depreciation and Amortization

Depreciation and amortization increased $213 million , or 10.5% , in 2016 as compared to the prior year primarily due to additional plant in service at the traditional electric operating companies and Southern Power.

Depreciation and amortization increased $91 million , or 4.7% , in 2015 as compared to the prior year primarily due to the amortization of $120 million of the regulatory liability for other cost of removal obligations in 2014 at Alabama Power and increases in additional plant in service at the traditional electric operating companies and Southern Power, partially offset by a decrease as a result of a reduction in depreciation rates at Alabama Power effective January 1, 2015, a decrease due to unit retirements at Georgia Power, and a reduction in depreciation at Gulf Power as authorized in the 2013 rate case settlement agreement approved by the Florida PSC. See Note 3 to the financial statements under " Regulatory Matters – Gulf Power – Retail Base Rate Cases " for additional information.

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

Taxes Other Than Income Taxes

Taxes other than income taxes increased $44 million , or 4.4% , in 2016 as compared to the prior year primarily due to an increase in property taxes due to higher assessed value of property at the traditional electric operating companies, increases in state and municipal utility license tax bases at Alabama Power, an increase in payroll taxes at Georgia Power, and an increase in franchise taxes at Mississippi Power.

Taxes other than income taxes increased $16 million , or 1.6% , in 2015 as compared to the prior year primarily due to an increase in property taxes due to higher assessed value of property at the traditional electric operating companies.

Estimated Loss on Kemper IGCC

In 2016, 2015, and 2014, estimated probable losses on the Kemper IGCC of $428 million , $365 million , and $868 million , respectively, were recorded at Southern Company. These losses reflect revisions of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC in excess of the $2.88 billion cost cap established by the Mississippi PSC, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (Initial DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions). The 2016 loss also reflects $80 million associated with the estimated minimum probable amount of costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017.

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

Allowance for Equity Funds Used During Construction

AFUDC equity decreased $26 million , or 11.5% , in 2016 as compared to the prior year primarily due to environmental and generation projects being placed in service at Alabama Power and Gulf Power, partially offset by a higher AFUDC rate and an increase in Kemper IGCC CWIP subject to AFUDC at Mississippi Power.

AFUDC equity decreased $19 million , or 7.8% , in 2015 as compared to the prior year primarily due to a reduction in the AFUDC rate at Mississippi Power, as well as placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service in August 2014, partially offset by an increase in construction projects related to environmental and steam generation at Alabama Power.

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

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $157 million , or 20.3% , in 2016 as compared to the prior year primarily due to an increase in interest expense at Southern Power related to additional debt issued primarily to fund its growth strategy and continuous construction program, increases in both the average outstanding long-term debt balance and the average interest rate at the traditional electric operating companies, and the May 2015 termination of an asset purchase agreement between Mississippi Power and SMEPA and the resulting reversal of accrued interest on related deposits.

Interest expense, net of amounts capitalized decreased $20 million , or 2.5% , in 2015 as compared to the prior year primarily due to a decrease of $58 million at Mississippi Power related to the termination of an agreement for SMEPA to purchase a portion of the Kemper IGCC which required the return of SMEPA's deposits at a lower rate of interest than accrued and a $14 million decrease primarily due to an increase in capitalized interest associated with the construction of solar facilities at Southern Power, partially offset by a $46 million increase due to higher average outstanding long-term debt balances at the traditional electric operating companies.

See Note 6 to the financial statements for additional information.

Other Income (Expense), Net

Other income (expense), net decreased $43 million , or 134.4% , in 2016 as compared to the prior year primarily due to the reclassification of revenues and costs associated with certain non-regulated sales of products and services by the traditional electric operating companies to other revenues and cost of other sales for consistency of presentation on a consolidated basis following the PowerSecure acquisition. The net amounts reclassified were $25 million. Also contributing to the decrease was an $8 million decrease in customer contributions in aid of construction (CIAC) and a $6 million decrease in wholesale operating fee revenue at Georgia Power.

Other income (expense), net increased $23 million , or 41.8% , in 2015 as compared to the prior year primarily due to an increase of $9 million in wholesale operating fee revenues, an increase of $9 million in customer CIAC at Georgia Power, and an increase due to Mississippi Power's $7 million settlement with the Sierra Club in 2014, partially offset by a decrease in sales of non-utility property at Alabama Power.

Income Taxes

Income taxes decreased $235 million , or 17.7% , in 2016 as compared to the prior year primarily due to increased federal income tax benefits related to ITCs for solar plants placed in service and PTCs from wind generation at Southern Power in 2016.

Income taxes increased $273 million , or 25.9% , in 2015 as compared to the prior year primarily due to a reduction in tax benefits related to the estimated probable losses on Mississippi Power's construction of the Kemper IGCC recorded in 2014 and higher pre-tax earnings, partially offset by increased federal income tax benefits related to ITCs at Southern Power in 2015.

See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Gas Business

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.

On July 1, 2016, Southern Company Gas became a wholly-owned, direct subsidiary of Southern Company. Prior to the completion of the Merger, Southern Company and Southern Company Gas operated as separate companies. The condensed statement of income herein includes Southern Company Gas' results of operations since July 1, 2016. See Note 12 to the financial statements under " Southern Company – Merger with Southern Company Gas " for additional information regarding the Merger, including certain pro forma results of operations.

A condensed statement of income for the gas business follows:

	Amount
	2016
	(in millions)
Operating revenues	$ 1,652
Cost of natural gas	613
Cost of other sales	10
Other operations and maintenance	523
Depreciation and amortization	238
Taxes other than income taxes	71
Total operating expenses	1,455
Operating income	197
Earnings from equity method investments	60
Interest expense, net of amounts capitalized	81
Other income (expense), net	14
Income taxes	76
Net income	114
Less: Net income attributable to noncontrolling interests	—
Net Income Attributable to Southern Company Gas	$ 114

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

Seasonality of Results

During the period from November through March when natural gas usage and operating revenues are generally higher (Heating Season), more customers are connected to Southern Company Gas' distribution systems, and natural gas usage is higher in periods of colder weather. Occasionally in the summer, operating revenues are impacted due to peak usage by power generators in response to summer energy demands. Southern Company Gas' base operating expenses, excluding cost of natural gas, bad debt expense, and certain incentive compensation costs, are incurred relatively equally over any given year. Thus, operating results can vary significantly from quarter to quarter as a result of seasonality. For July 1, 2016 through December 31, 2016, the percentage of operating revenues and net income generated during the Heating Season (November and December) were 67.1% and 96.5%, respectively.

Other Business Activities

Southern Company's other business activities include the parent company (which does not allocate operating expenses to business units), products and services in the areas of distributed generation, energy efficiency, and utility infrastructure, and investments in leveraged lease projects and telecommunications. These businesses are classified in general categories and may comprise the following subsidiaries: PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure; Southern Company Holdings, Inc. (Southern Holdings) invests in various projects, including leveraged lease projects; and Southern LINC provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast.

On May 9, 2016, Southern Company acquired all of the outstanding stock of PowerSecure for $18.75 per common share in cash, resulting in an aggregate purchase price of $429 million . As a result, PowerSecure became a wholly-owned subsidiary of Southern Company. See Note 12 to the financial statements under " Southern Company – Acquisition of PowerSecure " for additional information.

A condensed statement of income for Southern Company's other business activities follows:

	Amount	**Increase (Decrease) from Prior Year**	
	2016	**2016**	2015
		(in millions)	
Operating revenues	**$ 303**	**$ 256**	$ (14)
Cost of other sales	**192**	**192**	—
Other operations and maintenance	**194**	**70**	29
Depreciation and amortization	**31**	**17**	(2)
Taxes other than income taxes	**3**	**1**	—
Total operating expenses	**420**	**280**	27
Operating income (loss)	**(117)**	**(24)**	(41)
Interest expense	**305**	**239**	25
Other income (expense), net	**(31)**	**(24)**	(18)
Income taxes	**(216)**	**(84)**	(56)
Net income (loss)	**$ (237)**	**$ (203)**	$ (28)

Operating Revenues

Southern Company's non-electric operating revenues for these other business activities increased $256 million , or 544.7% , in 2016 as compared to the prior year. The increase was primarily related to revenues from products and services at PowerSecure, which was acquired on May 9, 2016. Non-electric operating revenues for these other business activities decreased $14 million , or 23.0% , in 2015 as compared to the prior year. The decrease was primarily related to lower operating revenues at Southern Holdings due to higher billings in 2014 related to work performed on a generating plant outage and decreases in revenues at Southern LINC related to lower average per subscriber revenue and fewer subscribers due to continued competition in the industry.

Cost of Other Sales

Cost of other sales were $192 million in 2016. These costs were primarily related to sales of products and services by PowerSecure, which was acquired on May 9, 2016.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses for these other business activities increased $70 million , or 56.5% , in 2016 as compared to the prior year. The increase was primarily due to $47 million in operations and maintenance expenses at PowerSecure since the acquisition closed on May 9, 2016 and an increase in parent company expenses of $16 million related to the Merger and the acquisition of PowerSecure. Other operations and maintenance expenses for these other business activities increased $29 million , or 30.5% , in 2015 as compared to the prior year. The increase was primarily due to parent company expenses of $27 million related to the Merger, partially offset by lower operating expenses at Southern Holdings due to work performed on a generating plant outage in 2014.

Other Income (Expense), Net

Other income (expense), net for these other business activities decreased $24 million in 2016 as compared to the prior year. The decrease was primarily due to an increase of $16 million in parent company expenses related to fees associated with the bridge financing for the Merger. Other income (expense), net for these other business activities decreased $18 million in 2015 as compared to the prior year. The decrease was primarily due to parent company expenses of $14 million related to fees associated with bridge financing for the Merger.

Interest Expense

Interest expense for these other business activities increased $239 million , or 362.1% , in 2016 as compared to the prior year primarily due to an increase in outstanding long-term debt at the parent company primarily relating to financing a portion of the purchase price for the Merger. Interest expense for these other business activities increased $25 million , or 61.0% , in 2015 as compared the prior year primarily due to an increase in outstanding long-term debt.

Income Taxes

Income taxes for these other business activities decreased $84 million , or 63.6% , in 2016 as compared to the prior year primarily as a result of changes in pre-tax earnings (losses), partially offset by state income tax benefits realized in 2015. Income taxes for these other business activities decreased $56 million , or 73.7% , in 2015 as compared to the prior year primarily as a result of state income tax benefits realized in 2015 and changes in pre-tax earnings (losses).

Effects of Inflation

The electric operating companies and natural gas distribution utilities are subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Southern Power is party to long-term contracts reflecting market-based rates, including inflation expectations. Any adverse effect of inflation on Southern Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The four traditional electric operating companies operate as vertically integrated utilities providing electric service to customers within their service territories in the Southeast. The seven natural gas distribution utilities provide service to customers in their service territories in Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee, and Maryland. Prices for electricity provided and natural gas distributed to retail customers are set by state PSCs or other applicable state regulatory agencies under cost-based regulatory principles. Prices for wholesale electricity sales and natural gas distribution, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Southern Power continues to focus on long-term PPAs. See ACCOUNTING POLICIES – " Application of Critical Accounting Policies and Estimates – Utility Regulation " herein and Note 3 to the financial statements for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of Southern Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Southern Company system's primary businesses of selling electricity and distributing natural gas. These factors include the traditional electric operating companies' and the natural gas distribution utilities' ability to maintain a constructive regulatory environment that allows for the timely recovery of prudently-incurred costs during a time of increasing costs and limited projected demand growth over the next several years. The completion and subsequent operation of the Kemper IGCC and Plant Vogtle Units 3 and 4, as well as other ongoing construction projects, and the profitability of Southern Power's competitive wholesale business and

successful additional investments in renewable and other energy projects are other major factors. Current proposals related to potential tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals, including any potential changes to the availability or realizability of ITCs and PTCs, is dependent on the final form of any legislation enacted and the related transition rules and cannot be determined at this time, but could have a material impact on Southern Company's financial statements.

Future earnings for the electricity and natural gas businesses will be driven primarily by customer growth. Earnings in the electricity business will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies, increasing volumes of electronic commerce transactions, and higher multi-family home construction. Earnings for both the electricity and natural gas businesses are subject to a variety of other factors. These factors include weather, competition, new energy contracts with other utilities and other wholesale customers, energy conservation practiced by customers, the use of alternative energy sources by customers, the prices of electricity and natural gas, the price elasticity of demand, and the rate of economic growth or decline in the service territory. In addition, the level of future earnings for the wholesale electric business also depends on numerous factors including regulatory matters, creditworthiness of customers, total electric generating capacity available and related costs, future acquisitions and construction of electric generating facilities, the impact of tax credits from renewable energy projects, and the successful remarketing of capacity as current contracts expire. Demand for electricity and natural gas is primarily driven by economic growth. The pace of economic growth and electricity and natural gas demand may be affected by changes in regional and global economic conditions, which may impact future earnings. In addition, the volatility of natural gas prices has a significant impact on the natural gas distribution utilities' customer rates, long-term competitive position against other energy sources, and the ability of Southern Company Gas' gas marketing services and wholesale gas services businesses to capture value from locational and seasonal spreads. Additionally, changes in commodity prices subject a significant portion of Southern Company Gas' operations to earnings variability.

As part of its ongoing effort to adapt to changing market conditions, Southern Company added several new businesses in 2016, including the acquisitions of Southern Company Gas, PowerSecure, and a 50% interest in the Southern Natural Gas Company, L.L.C. (SNG) pipeline system, as well as continued expansion of Southern Power's renewable energy projects portfolio. Southern Company continues to evaluate and consider a wide array of potential business strategies. These strategies may include business combinations, partnerships, and acquisitions involving other utility or non-utility businesses or properties, disposition of certain assets or businesses, internal restructuring, or some combination thereof. Furthermore, Southern Company may engage in new business ventures that arise from competitive and regulatory changes in the utility industry. Pursuit of any of the above strategies, or any combination thereof, may significantly affect the business operations, risks, and financial condition of Southern Company. See Note 12 to the financial statements for additional information regarding Southern Company's recent acquisition activity.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis for the traditional electric operating companies and the natural gas distribution utilities or through long-term wholesale agreements for the traditional electric operating companies and Southern Power. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are completed. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity and natural gas, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under " Environmental Matters " for additional information.

Environmental Statutes and Regulations

General

The Southern Company system's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; the Migratory Bird Treaty Act; the Bald and Golden Eagle Protection Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2016 , the traditional electric operating companies had invested approximately $11.9 billion in environmental capital retrofit projects to comply with

these requirements, with annual totals of approximately $0.5 billion, $0.9 billion, and $1.1 billion for 2016 , 2015 , and 2014 , respectively. The Southern Company system expects that capital expenditures to comply with environmental statutes and regulations will total approximately $2.9 billion from 2017 through 2021 , with annual totals of approximately $0.9 billion , $0.7 billion , $0.3 billion , $0.4 billion , and $0.6 billion for 2017 , 2018 , 2019 , 2020 , and 2021 , respectively. These estimated expenditures do not include any potential capital expenditures that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from existing, new, modified, or reconstructed fossil-fuel-fired electric generating units. See " Global Climate Issues " herein for additional information. The Southern Company system also anticipates costs associated with ash pond closure and ground water monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are reflected in the Company's ARO liabilities. See FINANCIAL CONDITION AND LIQUIDITY – " Capital Requirements and Contractual Obligations " herein and Note 1 to the financial statements under " Asset Retirement Obligations and Other Costs of Removal " for additional information.

The Southern Company system's ultimate environmental compliance strategy, including potential electric generating unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations, including the environmental regulations described below; the time periods over which compliance with regulations is required; individual state implementation of regulations, as applicable; the outcome of any legal challenges to the environmental rules; any additional rulemaking activities in response to legal challenges and court decisions; the cost, availability, and existing inventory of emissions allowances; the impact of future changes in generation and emissions-related technology; the fuel mix of the electric utilities; and environmental remediation requirements. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time.

Compliance with any new federal or state legislation or regulations relating to air, water, and land resources or other environmental and health concerns could significantly affect the Southern Company system. Although new or revised environmental legislation or regulations could affect many areas of the electric utilities' and natural gas distribution utilities' operations, the full impact of any such changes cannot be determined at this time. 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 and natural gas.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Southern Company system.

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

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard (NAAQS). In 2008, the EPA adopted a revised eight-hour ozone NAAQS and published its final area designations in 2012. The only area within the traditional electric operating companies' service territory designated as an ozone nonattainment area for the 2008 standard is a 15-county area within metropolitan Atlanta, which on December 23, 2016, the EPA proposed to redesignate to attainment. In October 2015, the EPA published a more stringent eight-hour ozone NAAQS. This new standard could potentially require additional emission controls, improvements in control efficiency, and operational fuel changes and could affect the siting of new generating facilities. States were required to recommend area designations by October 2016, and the only area within the Southern Company system's electric service territory that was proposed for designation is an eight-county area within the Atlanta metropolitan area in Georgia. The EPA is expected to finalize area designations by October 2017.

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

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

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

On July 6, 2011, the EPA finalized the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide (NO_x) emissions from power plants in two phases – Phase 1 in 2015 and Phase 2 in 2017. The Southern Company system has fossil generation in several states that were subject to the requirements of the 2011 CSAPR, including Alabama, Florida, Georgia, Mississippi, North Carolina, and Texas. On October 26, 2016, the EPA published a final rule that updates the CSAPR ozone season NO_x program, beginning in 2017, and establishes more stringent ozone-season emissions budgets in Alabama, Mississippi, and Texas and removes Florida and North Carolina from the ozone season program. Georgia's ozone season NO_x budget remains unchanged. North Carolina remains in the CSAPR annual SO_2 and NO_x programs, along with Alabama, Georgia, and Texas.

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

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

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

Water Quality

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

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

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

implementation of the final rule. The case is held in abeyance pending review by the U.S. Supreme Court of challenges to the U.S. Court of Appeals for the Sixth Circuit's jurisdiction in the case.

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

Coal Combustion Residuals

The traditional electric operating companies currently manage CCR at onsite storage units consisting of landfills and surface impoundments (CCR Units) at 23 current or former electric generating plants. In addition to on-site storage, the traditional electric operating companies also sell a portion of their CCR to third parties for beneficial reuse. Individual states regulate CCR and the states in the Southern Company system's electric service territory each have their own regulatory requirements. Each traditional electric operating company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

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

Based on current cost estimates for closure and monitoring of ash ponds pursuant to the CCR Rule, Southern Company has recorded incremental AROs related to the CCR Rule. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing with respect to compliance activities, the traditional electric operating companies expect to continue to periodically update these estimates. The traditional electric operating companies have posted closure and post-closure care plans to their public websites as required by the CCR Rule; however, the ultimate impact of the CCR Rule will depend on the results of initial and ongoing minimum criteria assessments and the implementation of state or federal permit programs. Southern Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. See Note 1 to the financial statements under " Asset Retirement Obligations and Other Costs of Removal " for additional information regarding Southern Company's AROs as of December 31, 2016.

Environmental Remediation

The Southern Company system must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Southern Company system could incur substantial costs to clean up affected sites. The traditional electric operating companies and Southern Company Gas conduct studies to determine the extent of any required cleanup and the Company has recognized in its financial statements the costs to clean up known impacted sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The traditional electric operating companies and the natural gas distribution utilities in Illinois, New Jersey, Georgia, and Florida have each received authority from their respective state PSCs or other applicable state regulatory agencies to recover approved environmental compliance costs through regulatory mechanisms. These regulatory mechanisms are adjusted annually or as necessary within limits approved by the state PSCs or other applicable state regulatory agencies. The traditional electric operating companies and Southern Company Gas may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under " Environmental Matters – Environmental Remediation " for additional information.

Global Climate Issues

In October 2015, the EPA published two final actions that would limit CO_2 emissions from fossil fuel-fired electric generating units. One of the final actions contains specific emission standards governing CO_2 emissions from new, modified, and reconstructed units. The other final action, known as the Clean Power Plan, establishes guidelines for states to develop plans to

meet EPA-mandated CO_2 emission rates or emission reduction goals for existing units. The EPA's final guidelines require state plans to meet interim CO_2 performance rates between 2022 and 2029 and final rates in 2030 and thereafter. At the same time, the EPA published a proposed federal plan and model rule that, when finalized, states can adopt or that would be put in place if a state either does not submit a state plan or its plan is not approved by the EPA. On February 9, 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan, pending disposition of petitions for review with the courts. The stay will remain in effect through the resolution of the litigation, including any review by the U.S. Supreme Court.

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

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

The EPA's greenhouse gas reporting rule requires annual reporting of greenhouse gas emissions expressed in terms of metric tons of CO_2 equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Southern Company system's 2015 greenhouse gas emissions were approximately 102 million metric tons of CO_2 equivalent. The preliminary estimate of the Southern Company system's 2016 greenhouse gas emissions on the same basis, including the addition of Southern Company Gas, is approximately 99 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation, the mix of fuel sources, and other factors.

FERC Matters

Market-Based Rate Authority

The traditional electric operating companies and Southern Power have authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric operating companies' 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 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 and Southern Power filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.

On December 9, 2016, the traditional electric operating companies 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' and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The traditional electric operating companies and Southern Power expect to make a compliance filing within 30 days accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

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

Southern Company Gas

At December 31, 2016, Southern Company Gas' gas midstream operations was involved in three gas pipeline construction projects with expected capital expenditures of approximately $780 million . These projects, along with Southern Company Gas' existing pipelines, are intended to provide diverse sources of natural gas supplies to customers, resolve current and long-term

supply planning for new capacity, enhance system reliability, and generate economic development in the areas served. One of these projects received FERC approval in August 2016. The remaining projects are pending FERC approval, which is expected to occur in 2017. The ultimate outcome of this matter cannot be determined at this time.

Regulatory Matters

Alabama Power

Alabama Power 's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Alabama PSC. Alabama Power currently recovers its costs from the regulated retail business primarily through Rate RSE, Rate CNP, Rate ECR, and Rate NDR. In addition, the Alabama PSC issues accounting orders to address current events impacting Alabama Power. See Note 3 to the financial statements under " Regulatory Matters – Alabama Power " for additional information regarding Alabama Power's rate mechanisms and accounting orders.

Rate RSE

The Alabama PSC has adopted Rate RSE that provides for periodic annual adjustments based upon Alabama Power's projected weighted cost of equity (WCE) compared to an allowable range. Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate RSE adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. If Alabama Power's actual retail return is above the allowed WCE range, 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.

On December 1, 2016, Alabama Power made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2017. The Rate RSE adjustment was an increase of 4.48%, or $245 million annually, effective January 1, 2017 and includes the performance based adder of 0.07%. Under the terms of Rate RSE, the maximum increase for 2018 cannot exceed 3.52%.

As of December 31, 2016, the 2016 retail return exceeded the allowed WCE range; therefore, Alabama Power established a $73 million Rate RSE refund liability. In accordance with an order issued on February 14, 2017 by the Alabama PSC, Alabama Power was directed to apply the full amount of the refund to reduce the under recovered balance of Rate CNP PPA.

Rate CNP PPA

Alabama Power's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under Rate CNP. Alabama Power may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 8, 2016, the Alabama PSC issued a consent order that Alabama Power leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2016 through March 31, 2017. No adjustment to Rate CNP PPA is expected in 2017.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, Alabama Power was authorized to eliminate the under recovered balance in Rate CNP PPA at December 31, 2016, which totaled approximately $142 million. As discussed herein under "Rate RSE," Alabama Power will utilize the full amount of its $73 million Rate RSE refund liability to reduce the amount of the Rate CNP PPA under recovery and will reclassify 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 Alabama Power's next depreciation study, which is expected to occur within the next three to five years. Alabama Power's current depreciation study became effective January 1, 2017.

Rate CNP Compliance

Rate CNP Compliance allows for the recovery of Alabama Power'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 Alabama Power'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 Rate CNP Compliance related operations and maintenance expenses and depreciation generally will have no effect on net income.

On December 6, 2016, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2017 the factors associated with Alabama Power's compliance costs for the year 2016. As stated in the consent order, any under-collected amount

for prior years will be deemed recovered before the recovery of any current year amounts. Any under recovered amounts associated with 2017 will be reflected in the 2018 filing.

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

Environmental Accounting Order

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

In April 2016, as part of its environmental compliance strategy, Alabama Power ceased using coal at Plant Greene County Units 1 and 2 (300 MWs representing Alabama Power's ownership interest) and began operating Units 1 and 2 solely on natural gas in June 2016 and July 2016, respectively. As a result, Alabama Power transferred the unrecovered plant asset balances to a regulatory asset at their respective retirement dates. The regulatory asset will be amortized and recovered through Rate CNP Compliance over the units' remaining useful lives, as established prior to the decision for retirement; therefore, these decisions associated with coal operations had no significant impact on Southern Company's financial statements.

Georgia Power

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

Rate Plans

Pursuant to the terms and conditions of a settlement agreement related to Southern Company's acquisition of Southern Company Gas approved by the Georgia PSC on April 14, 2016, the 2013 ARP will continue in effect until December 31, 2019, and Georgia Power will be required to file its next base rate case by July 1, 2019. Furthermore, through December 31, 2019, Georgia Power and Atlanta Gas Light Company each will retain their respective merger savings, net of transition costs, as defined in the settlement agreement; through December 31, 2022, such net merger savings applicable to each will be shared on a 60/40 basis with their respective customers; thereafter, all merger savings will be retained by customers. See Note 3 to the financial statements under " Regulatory Matters – Georgia Power – Rate Plans " for additional information regarding the 2013 ARP and Note 12 to the financial statements under " Southern Company – Merger with Southern Company Gas " for additional information regarding the Merger.

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

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

Integrated Resource Plan

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

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

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

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

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

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

Storm Damage Recovery

As of December 31, 2016, the balance in Georgia Power's regulatory asset related to storm damage was $206 million . During October 2016, Hurricane Matthew caused significant damage to Georgia Power's transmission and distribution facilities. As of December 31, 2016, Georgia Power had recorded incremental restoration cost related to this hurricane of $121 million, of which approximately $116 million was charged to the storm damage reserve and the remainder was capitalized. Georgia Power is accruing $30 million annually through December 31, 2019, as provided in the 2013 ARP, to the storm damage reserve to cover the operations and maintenance costs of damages from major storms to its transmission and distribution facilities, which is recoverable through base rates. The rate of recovery of storm damage costs after December 31, 2019 is expected to be adjusted in Georgia Power's 2019 base rate case. As a result of this regulatory treatment, costs related to storms are not expected to have a material impact on Southern Company's financial statements. See Note 3 to the financial statements under " Regulatory Matters – Georgia Power – Storm Damage Recovery " for additional information regarding Georgia Power's storm damage reserve.

Gulf Power

Through 2015, long-term non-affiliate capacity sales from Gulf Power's ownership of Plant Scherer Unit 3 (205 MWs) provided the majority of Gulf Power's wholesale earnings. Contract expirations at the end of 2015 and the end of May 2016 related to Plant Scherer Unit 3 wholesale sales did not have a material impact on Southern Company's earnings in 2016. Remaining contract sales from Plant Scherer Unit 3 cover approximately 24% of Gulf Power's ownership of the unit through 2019.

On October 12, 2016, Gulf Power filed a petition (2016 Rate Case) with the Florida PSC requesting an annual increase in retail rates and charges of $106.8 million based on the projected test year of January 1, 2017 through December 31, 2017 and a retail ROE of 11% compared to the current retail ROE of 10.25%. The requested increase includes recovery of the portion of Plant Scherer Unit 3 that has been rededicated to serving retail customers following the contract expirations discussed above. If retail recovery of Plant Scherer Unit 3 is not approved by the Florida PSC in the 2016 Rate Case, Gulf Power may consider an asset sale. The current book value of Gulf Power's ownership of Plant Scherer Unit 3 could exceed market value which could result in a material loss. The Florida PSC is expected to make a decision on the 2016 Rate Case in the second quarter 2017. Gulf Power has requested that the increase in base rates, if approved by the Florida PSC, become effective in July 2017.

On November 2, 2016, the Florida PSC approved Gulf Power's 2017 annual cost recovery clause factors. The fuel and environmental factors include certain costs associated with the ongoing ownership and operation of Plant Scherer Unit 3. The

final disposition of these costs, and the related impact on rates, is subject to the Florida PSC's ultimate ruling on whether costs associated with Plant Scherer Unit 3 are recoverable from retail customers, which is expected to be decided in the 2016 Rate Case as discussed previously.

See Note 3 to the financial statements under " Regulatory Matters – Gulf Power – Retail Base Rate Cases " for additional information. The ultimate outcome of these matters cannot be determined at this time.

Southern Company Gas

Natural Gas Cost Recovery

Southern Company Gas has established natural gas cost recovery rates that are approved by the applicable state regulatory agencies in the states in which it serves. Natural gas cost recovery revenues are adjusted for differences in actual recoverable natural gas costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect cash flow.

Regulatory Infrastructure Programs

Six of Southern Company Gas' seven natural gas distribution utilities are involved in ongoing capital projects associated with infrastructure improvement programs that have been previously approved by their applicable state regulatory agencies and provide an appropriate return on invested capital. These infrastructure improvement programs are designed to update or expand the natural gas distribution systems of the natural gas distribution utilities to improve reliability and meet operational flexibility and growth. Initial program lengths range from four to 10 years, with the longest set to expire in 2025. The total expected investment under these programs for 2017 is $590 million .

On February 21, 2017, the Georgia PSC approved a rate adjustment mechanism for Atlanta Gas Light that included the 2017 capital investment associated with a four-year extension of one of its existing infrastructure programs, with a total additional investment of $177 million through 2020. In addition, Elizabethtown Gas currently has a proposed infrastructure improvement program pending approval by the New Jersey Board of Public Utilities requesting to invest more than $1.1 billion through 2027.

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

Renewables

In accordance with the September 2015 Alabama PSC order approving up to 500 MWs of renewable projects, Alabama Power has entered into agreements to purchase power from and to build 89 MWs of renewable generation sources. The terms of the agreements permit Alabama Power to use the energy and retire the associated renewable energy credits (REC) in service of its customers or to sell RECs, separately or bundled with energy.

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

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

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

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

See " Georgia Power – Integrated Resource Plan " herein for additional information on Georgia Power's renewables.

In April 2015, the Florida PSC approved Gulf Power's three energy purchase agreements totaling 120 MWs of utility-scale solar generation located at three military installations in northwest Florida. Purchases under these solar agreements are expected to begin by the summer of 2017.

The Florida PSC issued a final approval order on Gulf Power's Community Solar Pilot Program on April 15, 2016. The program will offer Gulf Power's customers an opportunity to voluntarily contribute to the construction and operation of a solar photovoltaic facility with electric generating capacity of up to 1 MW through annual subscriptions. The energy generated from the solar facility is expected to provide power to all of Gulf Power's customers.

On November 29, 2016, the Florida PSC approved Gulf Power's energy purchase agreement for up to 94 MWs of additional wind generation in central Oklahoma. Purchases under this agreement will be for energy only and will be recovered through Gulf Power's fuel cost recovery clause.

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

See Note 12 to the financial statements for information on Southern Power's renewables activities.

Fuel Cost Recovery

The traditional electric operating companies each have established fuel cost recovery rates approved by their respective state PSCs. Fuel cost recovery revenues are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect cash flow. The traditional electric operating companies continuously monitor their under or over recovered fuel cost balances and make appropriate filings with their state PSCs to adjust fuel cost recovery rates as necessary.

See Note 1 to the financial statements under " Revenues " and Note 3 to the financial statements under " Regulatory Matters – Alabama Power – Rate ECR " and " Regulatory Matters – Georgia Power – Fuel Cost Recovery " for additional information.

Construction Program

Overview

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. The Southern Company system intends to continue its strategy of developing and constructing new electric generating facilities, adding environmental modifications to certain existing units, expanding the electric transmission and distribution systems, and updating and expanding the natural gas distribution systems. For the traditional electric operating companies, major generation construction projects are subject to state PSC approval in order to be included in retail rates. While Southern Power generally constructs and acquires generation assets covered by long-term PPAs, any uncontracted capacity could negatively affect future earnings. Southern Company Gas is engaged in various infrastructure improvement programs designed to update or expand the natural gas distribution systems of the natural gas distribution utilities to improve reliability and meet operational flexibility and growth. The natural gas distribution utilities recover their investment and a return associated with these infrastructure programs through their regulated rates. The Southern Company system's construction program is currently estimated to total approximately $9.1 billion , $8.2 billion , $7.3 billion , $6.9 billion , and $6.4 billion for 2017 , 2018 , 2019 , 2020 , and 2021 , respectively.

The two largest construction projects currently underway in the Southern Company system are Plant Vogtle Units 3 and 4 (45.7% ownership interest by Georgia Power in the two units, each with approximately 1,100 MWs) and Mississippi Power's Kemper IGCC. See Note 3 to the financial statements under " Regulatory Matters – Georgia Power – Nuclear Construction " and " Integrated Coal Gasification Combined Cycle " for additional information. See Note 12 to the financial statements under " Southern Power – Construction Projects " for additional information about costs relating to Southern Power's acquisitions that involve construction of renewable energy facilities. See Note 3 to the financial statements under " Regulatory Matters – Southern Company Gas – Regulatory Infrastructure Programs " for additional information regarding infrastructure improvement programs at the natural gas distribution utilities.

Also see FINANCIAL CONDITION AND LIQUIDITY – " Capital Requirements and Contractual Obligations " herein for additional information regarding Southern Company's capital requirements for its subsidiaries' construction programs.

Integrated Coal Gasification Combined Cycle

Mississippi Power continues to progress toward completing the construction and start-up of the Kemper IGCC, which was approved by the Mississippi PSC in the 2010 CPCN proceedings, subject to a construction cost cap of $2.88 billion, net of $245 million of Initial DOE Grants and excluding the Cost Cap Exceptions. The current cost estimate for the Kemper IGCC in total is

approximately $6.99 billion , which includes approximately $5.64 billion of costs subject to the construction cost cap and is net of the $137 million in additional grants from the DOE received on April 8, 2016 (Additional DOE Grants), which are expected to be used to reduce future rate impacts to customers. Mississippi Power does not intend to seek any rate recovery for any related costs that exceed the $ 2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. Southern Company recorded pre-tax charges to income for revisions to the cost estimate subject to the construction cost cap totaling $348 million ($215 million after tax), $365 million ($226 million after tax), and $868 million ($536 million after tax) in 2016 , 2015 , and 2014 , respectively. Since 2013, in the aggregate, Southern Company has incurred charges of $2.76 billion ($1.71 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2016 . The current cost estimate includes costs through March 15, 2017.

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

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

Upon placing the remainder of the plant in service, Mississippi Power will be primarily focused on completing the regulatory cost recovery process. In December 2015, the Mississippi PSC issued an order, based on a stipulation between Mississippi Power and the MPUS, authorizing rates that provide for the recovery of approximately $126 million annually related to Kemper IGCC assets previously placed in service.

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

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

2017 Annual Fuel Forecast and, to a lesser extent, the increase in the estimated Kemper IGCC operating costs, negatively impact the updated project economic viability analysis.

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

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

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

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

Southern Company and Mississippi Power are defendants in various lawsuits that allege improper disclosure about the Kemper IGCC, as discussed below under "Litigation." In addition, the SEC is conducting a formal investigation of Southern Company and Mississippi Power concerning the estimated costs and expected in-service date of the Kemper IGCC. Southern Company believes the investigation is focused primarily on periods subsequent to 2010 and on accounting matters, disclosure controls and procedures, and internal controls over financial reporting associated with the Kemper IGCC. See "Other Matters" herein for additional information.

The ultimate outcome of these matters cannot be determined at this time. See Note 3 to the financial statements under " Integrated Coal Gasification Combined Cycle " for additional information.

Litigation

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

On June 9, 2016, Treetop Midstream Services, LLC (Treetop) and other related parties filed a complaint against Mississippi Power, Southern Company, and SCS in the state court in Gwinnett County, Georgia. The complaint relates to the cancelled CO_2 contract with Treetop and alleges fraudulent misrepresentation, fraudulent concealment, civil conspiracy, and breach of contract on the part of Mississippi Power, Southern Company, and SCS and seeks compensatory damages of $100 million, as well as unspecified punitive damages. Southern Company, Mississippi Power, and SCS have moved to compel arbitration pursuant to the terms of the CO_2 contract.

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

Nuclear Construction

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

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

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

On February 14, 2017, Toshiba announced preliminary earnings results for the period ended December 31, 2016, which included a substantial goodwill impairment charge at Westinghouse attributed to increased cost estimates to complete its U.S. nuclear projects, including Plant Vogtle Units 3 and 4. Toshiba also warned that it will likely be in a negative equity position as a result of the charges. At the same time, Toshiba reaffirmed its commitment to its U.S. nuclear projects with implementation of

management changes and increased oversight. An inability or failure by the Contractor to perform its obligations under the Vogtle 3 and 4 Agreement could have a material impact on the construction of Plant Vogtle Units 3 and 4.

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

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

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

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

On December 20, 2016, the Georgia PSC voted to approve a settlement agreement (Vogtle Cost Settlement Agreement) resolving the following prudence matters: (i) none of the $3.3 billion of costs incurred through December 31, 2015 and reflected in the fourteenth VCM report will be disallowed from rate base on the basis of imprudence; (ii) the Contractor Settlement Agreement is reasonable and prudent and none of the amounts paid or to be paid pursuant to the Contractor Settlement Agreement should be disallowed from rate base on the basis of imprudence; (iii) financing costs on verified and approved capital costs will be deemed prudent provided they are incurred prior to December 31, 2019 and December 31, 2020 for Plant Vogtle Units 3 and 4, respectively; and (iv) (a) the in-service capital cost forecast will be adjusted to $5.680 billion (Revised Forecast), which includes a contingency of $240 million above Georgia Power's current forecast of $5.440 billion , (b) capital costs incurred up to the

Revised Forecast will be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, and (c) Georgia Power would have the burden to show that any capital costs above the Revised Forecast are reasonable and prudent. Under the terms of the Vogtle Cost Settlement Agreement, the certified in-service capital cost for purposes of calculating the NCCR tariff will remain at $4.418 billion . Construction capital costs above $4.418 billion will accrue AFUDC through the date each unit is placed in service. The ROE used to calculate the NCCR tariff was reduced from 10.95% (the ROE rate setting point authorized by the Georgia PSC in the 2013 ARP) to 10.00% effective January 1, 2016. For purposes of the AFUDC calculation, the ROE on costs between $4.418 billion and $5.440 billion will also be 10.00% and the ROE on any amounts above $5.440 billion would be Georgia Power's average cost of long-term debt. If the Georgia PSC adjusts Georgia Power's ROE rate setting point in a rate case prior to Plant Vogtle Units 3 and 4 being placed into retail rate base, then the ROE for purposes of calculating both the NCCR tariff and AFUDC will likewise be 95 basis points lower than the revised ROE rate setting point. If Plant Vogtle Units 3 and 4 are not placed in service by December 31, 2020, then (i) the ROE for purposes of calculating the NCCR tariff will be reduced an additional 300 basis points, or $8 million per month, and may, at the Georgia PSC's discretion, be accrued to be used for the benefit of customers, until such time as the units are placed in service and (ii) the ROE used to calculate AFUDC will be Georgia Power's average cost of long-term debt.

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

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

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

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

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

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

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

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

Income Tax Matters

Bonus Depreciation

In December 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service through 2020. The PATH Act allows for 50% bonus depreciation for 2015 through 2017, 40% bonus depreciation for 2018, and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. The extension of bonus depreciation included in the PATH Act is expected to result in approximately $1.3 billion of positive cash flows for the 2016 tax year, which was not all realized in 2016 due to a projected consolidated net operating loss (NOL) for Southern Company. Approximately $1.2 billion of positive cash flows is expected to result from bonus depreciation for the 2017 tax year, but may not all be realized in 2017 due to additional NOL projections for the 2017 tax year. As a result of the schedule extension for the Kemper IGCC, approximately $370 million of the 2017 benefit is dependent upon placing the remainder of the Kemper IGCC in service by December 31, 2017. See Note 3 to the financial statements under " Integrated Coal Gasification Combined Cycle " and Note 5 to the financial statements under " Current and Deferred Income Taxes – Net Operating Loss " for additional information. The ultimate outcome of this matter cannot be determined at this time.

Tax Credits

The PATH Act allows for 30% ITC for solar projects that commence construction by December 31, 2019; 26% ITC for solar projects that commence construction in 2020; 22% ITC for solar projects that commence construction in 2021; and a permanent 10% ITC for solar projects that commence construction on or after January 1, 2022. In addition, the PATH Act extended the PTC for wind projects with a phase out that allows for 100% PTC for wind projects that commenced construction in 2016; 80% PTC for wind projects that commence construction in 2017; 60% PTC for wind projects that commence construction in 2018; and 40% PTC for wind projects that commence construction in 2019. The Company has received ITCs and PTCs in connection with investments in solar, wind, and biomass facilities primarily at Southern Power and Georgia Power. See Note 1 to the financial statements under " Income and Other Taxes " and Note 5 to the financial statements under " Current and Deferred Income Taxes – Tax Credit Carryforwards " for additional information regarding utilization and amortization of credits and the tax benefit related to basis differences.

Section 174 Research and Experimental Deduction

Southern Company reflected deductions for research and experimental (R&E) expenditures related to the Kemper IGCC in its federal income tax calculations since 2013 and filed amended federal income tax returns for 2008 through 2013 to also include such deductions. In December 2016, Southern Company and the IRS reached a proposed settlement, subject to approval of the U.S. Congress Joint Committee on Taxation, resolving a methodology for these deductions. Due to the uncertainty related to this tax position, Southern Company had unrecognized tax benefits associated with these R&E deductions totaling approximately $464 million as of December 31, 2016 . See " Bonus Depreciation " herein and Note 5 to the financial statements under " Unrecognized Tax Benefits " for additional information. This matter is expected to be resolved in the next 12 months; however, the ultimate outcome of this matter cannot be determined at this time.

Other Matters

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

The ultimate outcome of such pending or potential litigation against Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management

does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

On January 20, 2017, a purported securities class action complaint was filed against Southern Company and certain of its and Mississippi Power's officers in the U.S. District Court for the Northern District of Georgia, Atlanta Division, by Monroe County Employees' Retirement System on behalf of all persons who purchased shares of Southern Company's common stock between April 25, 2012 and October 29, 2013. The complaint alleges that Southern Company and certain of its and Mississippi Power's officers made materially false and misleading statements regarding the Kemper IGCC in violation of certain provisions under the Securities Exchange Act of 1934, as amended. The complaint seeks, among other things, compensatory damages and litigation costs and attorneys' fees. Southern Company believes this legal challenge has no merit; however, an adverse outcome in this proceeding could have an impact on Southern Company's results of operations, financial condition, and liquidity. Southern Company will vigorously defend itself in this matter, and the ultimate outcome of this matter cannot be determined at this time.

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

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Utility Regulation

Southern Company's traditional electric operating companies and natural gas distribution utilities, which collectively comprised approximately 91% of Southern Company's total operating revenues for 2016 , are subject to retail regulation by their respective state PSCs or other applicable state regulatory agencies and wholesale regulation by the FERC. These regulatory agencies set the rates the traditional electric operating companies and the natural gas distribution utilities are permitted to charge customers based on allowable costs, including a reasonable ROE. As a result, the traditional electric operating companies and the natural gas distribution utilities apply accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the traditional electric operating companies and the natural gas distribution utilities; 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.

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

During 2016 , Mississippi Power further revised its cost estimate to complete construction and start-up of the Kemper IGCC to an amount that exceeds the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. Mississippi

Power does not intend to seek any rate recovery for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions.

As a result of revisions to the cost estimate, Southern Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC subject to the construction cost cap of $127 million ($78 million after tax) in the fourth quarter 2016, $88 million ($54 million after tax) in the third quarter 2016, $81 million ($50 million after tax) in the second quarter 2016, $53 million ($33 million after tax) in the first quarter 2016, $183 million ($113 million after tax) in the fourth quarter 2015, $150 million ($93 million after tax) in the third quarter 2015, $23 million ($14 million after tax) in the second quarter 2015, $9 million ($6 million after tax) in the first quarter 2015, $70 million ($43 million after tax) in the fourth quarter 2014, $418 million ($258 million after tax) in the third quarter 2014, $380 million ($235 million after tax) in the first quarter 2014, $40 million ($25 million after tax) in the fourth quarter 2013, $150 million ($93 million after tax) in the third quarter 2013, $450 million ($278 million after tax) in the second quarter 2013, and $540 million ($333 million after tax) in the first quarter 2013. In the aggregate, Southern Company has incurred charges of $2.76 billion ($1.71 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2016 .

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

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

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

Mississippi Power continues to believe that all costs related to the Kemper IGCC have been prudently incurred in accordance with the requirements of the 2012 MPSC CPCN Order. Mississippi Power also recognizes significant areas of potential challenge during future regulatory proceedings (and any subsequent, related legal challenges) exist. As described further in Note 3 to the financial statements under " Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs ," " – Prudence ," " – Lignite Mine and CO_2 Pipeline Facilities ," " – Termination of Proposed Sale of Undivided Interest ," " – Bonus Depreciation," " – Investment Tax Credits," and " – Section 174 Research and Experimental Deduction," these challenges include, but are not limited to, prudence issues associated with capital costs, financing costs (AFUDC), and future operating costs, net of chemical revenues; potential operating parameters; income tax issues; costs deferred as regulatory assets; and the 15% portion of the project previously contracted to SMEPA.

Although the 2017 Rate Case has not yet been filed and is subject to future developments with either the Kemper IGCC or the Mississippi PSC, consistent with its approach in the 2013 and 2015 rate proceedings in accordance with the law passed in 2013 authorizing multi-year rate plans, Mississippi Power is developing both a traditional rate case requesting full cost recovery of the amounts not currently in rates and a rate mitigation plan that together represent Mississippi Power's probable filing strategy. Mississippi Power also expects that timely resolution of the 2017 Rate Case will likely require a negotiated settlement agreement. In the event an agreement acceptable to both Mississippi Power and the MPUS (and other parties) can be negotiated and ultimately approved by the Mississippi PSC, it is reasonably possible that full regulatory recovery of all Kemper IGCC costs will not occur. The impact of such an agreement on Southern Company's financial statements would depend on the method, amount,

and type of cost recovery ultimately excluded. Certain costs, including operating costs, would be recorded to income in the period incurred, while other costs, including investment-related costs, would be charged to income when it is probable they will not be recovered and the amounts can be reasonably estimated. In the event an agreement acceptable to the parties cannot be reached, Mississippi Power intends to fully litigate its request for full recovery through the Mississippi PSC regulatory process and any subsequent legal challenges.

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

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

Asset Retirement Obligations

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

The liability for AROs primarily relates to facilities that are subject to the CCR Rule, principally ash ponds, and the decommissioning of the Southern Company system's nuclear facilities – Alabama Power's Plant Farley and Georgia Power's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2. In addition, the Southern Company system has retirement obligations related to various landfill sites, asbestos removal, mine reclamation, land restoration related to solar and wind facilities, and disposal of polychlorinated biphenyls in certain transformers. The Southern Company system also has identified retirement obligations related to certain electric transmission and distribution facilities, certain wireless communication towers, property associated with the Southern Company system's rail lines and natural gas pipelines, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded as the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO.

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

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

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

Pension and Other Postretirement Benefits

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

Key elements in determining Southern Company's pension and other postretirement benefit expense are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on Southern Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. Southern Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to Southern Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, Southern Company discounts the future related cash flows using a single-point discount rate for each plan developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. For 2015 and prior years, Southern Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. For 2016, Southern Company 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 $96 million in 2016.

The following table illustrates the sensitivity to changes in Southern Company's long-term assumptions with respect to the assumed discount rate, the assumed salaries, and the assumed long-term rate of return on plan assets:

Change in Assumption	**Increase/(Decrease) in Total Benefit Expense for 2017**	**Increase/(Decrease) in Projected Obligation for Pension Plan at December 31, 2016**	**Increase/(Decrease) in Projected Obligation for Other Postretirement Benefit Plans at December 31, 2016**
		(in millions)	
25 basis point change in discount rate	$34/$(39)	$418/$(396)	$64/$(61)
25 basis point change in salaries	$20/$(19)	$97/$(94)	$–/$–
25 basis point change in long-term return on plan assets	$31/$(31)	N/A	N/A

N/A – Not applicable

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

Goodwill and Other Intangible Assets

The acquisition method of accounting requires the assets acquired and liabilities assumed to be recorded at the date of acquisition at their respective estimated fair values. Southern Company recognizes goodwill as of the acquisition date, as a residual over the fair values of the identifiable net assets acquired. Goodwill is tested for impairment on an annual basis in the fourth quarter of the year as well as on an interim basis as events and changes in circumstances occur. Primarily as a result of the acquisitions of Southern Company Gas and PowerSecure in 2016, goodwill totaled approximately $6.3 billion at December 31, 2016 .

Definite-lived intangible assets acquired are amortized over the estimated useful lives of the respective assets to reflect the pattern in which the economic benefits of the intangible assets are consumed. Whenever events or changes in circumstances indicate that the carrying amount of the intangible assets may not be recoverable, the intangible assets will be reviewed for impairment. Primarily as a result of the acquisitions of Southern Company Gas and PowerSecure and PPA fair value adjustments resulting from Southern Power's acquisitions, other intangible assets, net of amortization totaled approximately $1.0 billion at December 31, 2016 .

The judgments made in determining the estimated fair value assigned to each class of assets acquired and liabilities assumed, as well as asset lives, can significantly impact Southern Company's results of operations. Fair values and useful lives are determined based on, among other factors, the expected future period of benefit of the asset, the various characteristics of the asset, and projected cash flows. As the determination of an asset's fair value and useful life involves management making certain estimates and because these estimates form the basis for the determination of whether or not an impairment charge should be recorded, Southern Company considers these estimates to be critical accounting estimates.

See Note 1 to the financial statements under " Goodwill and Other Intangible Assets and Liabilities " for additional information regarding Southern Company's goodwill and other intangible assets and Note 12 to the financial statements for additional information related to Southern Company's recent acquisitions.

Derivatives and Hedging Activities

Derivative instruments are recorded on the balance sheets as either assets or liabilities measured at their fair value, unless the

transactions qualify for the normal purchases or normal sales scope exception and are instead subject to traditional accrual accounting. For those transactions that do not qualify as a normal purchase or normal sale, changes in the derivatives' fair values are recognized concurrently in earnings unless specific hedge accounting criteria are met. If the derivatives meet those criteria, derivative gains and losses offset related results of the hedged item in the income statement in the case of a fair value hedge, or gains and losses are deferred in OCI until the hedged transaction affects earnings in the case of a cash flow hedge. Certain subsidiaries of Southern Company enter into energy-related derivatives that are designated as regulatory hedges where gains and losses are initially recorded as regulatory liabilities and assets and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through billings to customers.

Southern Company uses derivative instruments to reduce the impact to the results of operations due to the risk of changes in the price of natural gas, to manage fuel hedging programs per guidelines of state regulatory agencies, and to mitigate residual changes in the price of electricity, weather, interest rates, and foreign currency exchange rates. The fair value of commodity derivative instruments used to manage exposure to changing prices reflects the estimated amounts that Southern Company would receive or pay to terminate or close the contracts at the reporting date. To determine the fair value of the derivative instruments, Southern Company utilizes market data or assumptions that market participants would use in pricing the derivative asset or liability, including assumptions about risk and the risks inherent in the inputs of the valuation technique.

Southern Company classifies derivative assets and liabilities based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. The determination of the fair value of the derivative instruments incorporates various required factors. These factors include:

- the creditworthiness of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit);
- events specific to a given counterparty; and
- the impact of Southern Company's nonperformance risk on its liabilities.

Given the assumptions used in pricing the derivative asset or liability, Southern Company considers the valuation of derivative assets and liabilities a critical accounting estimate. See FINANCIAL CONDITION AND LIQUIDITY – " Market Price Risk " herein for more information.

Contingent Obligations

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

Recently Issued Accounting Standards

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

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

Southern Company's ongoing evaluation of other revenue streams and related contracts includes longer term contractual commitments and unregulated sales to customers. Some revenue arrangements, such as certain PPAs and alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on Southern Company's financial statements. In addition, the power and utilities industry is currently

addressing other specific industry issues, including the applicability of ASC 606 to CIAC. If final implementation guidance indicates CIAC will be accounted for under ASC 606 and offsetting regulatory treatment is not permitted, it could have a material impact on Southern Company's financial statements.

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

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

On March 30, 2016, the FASB issued ASU No. 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, Southern 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. Southern 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. Southern 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 Southern Company. See Notes 5, 8, and 14 to the financial statements for disclosures impacted by ASU 2016-09.

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

On November 17, 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* (ASU 2016-18). ASU 2016-18 eliminates the need to reflect transfers between cash and restricted cash in operating, investing, and financing activities in the statement of cash flows. Upon adoption, the net change in cash and cash equivalents during the period will include amounts generally described as restricted cash or restricted cash equivalents. ASU 2016-18 is effective for fiscal years beginning after December 15, 2017, with early adoption permitted, and will be applied retrospectively to each period presented. Southern Company does not intend to adopt the guidance early. The adoption of ASU 2016-18 will not have a material impact on the financial statements of Southern Company.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Earnings in all periods presented were negatively affected by revisions to the cost estimate for the Kemper IGCC; however, Southern Company's financial condition remained stable at December 31, 2016 .

The Southern Company system's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. The Southern Company system's capital expenditures and other investing activities include investments to meet projected long-term demand requirements, including to build new electric generation facilities, to maintain existing electric generation facilities, to comply with environmental regulations including adding environmental modifications to certain existing electric generating units, to expand and improve electric transmission and distribution facilities,

to update and expand natural gas distribution systems, and for restoration following major storms. Operating cash flows provide a substantial portion of the Southern Company system's cash needs. For the three-year period from 2017 through 2019 , Southern Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Southern Company plans to finance future cash needs in excess of its operating cash flows primarily by accessing borrowings from financial institutions and through debt and equity issuances in the capital markets. Southern Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit arrangements to meet future capital and liquidity needs. See FUTURE EARNINGS POTENTIAL – " Income Tax Matters – Bonus Depreciation " and " Sources of Capital ," " Financing Activities ," and " Capital Requirements and Contractual Obligations " herein for additional information.

Southern Company's investments in the qualified pension plans and the nuclear decommissioning trust funds increased in value as of December 31, 2016 as compared to December 31, 2015 . On December 19, 2016, the traditional electric operating companies and certain other subsidiaries voluntarily contributed an aggregate of $900 million to Southern Company's qualified pension plan. In addition, on September 12, 2016, Southern Company Gas voluntary contributed $125 million to its qualified pension plan. No mandatory contributions to the qualified pension plans are anticipated during 2017 . See " Contractual Obligations " herein and Notes 1 and 2 to the financial statements under " Nuclear Decommissioning " and " Pension Plans ," respectively, for additional information.

Net cash provided from operating activities in 2016 totaled $4.9 billion , a decrease of $1.4 billion from 2015 . The decrease in net cash provided from operating activities was primarily due to voluntary contributions to the qualified pension plan of approximately $1.0 billion and a $1.2 billion increase in unutilized ITCs and PTCs. Net cash provided from operating activities in 2015 totaled $6.3 billion , an increase of $459 million from 2014 . Significant changes in operating cash flow for 2015 as compared to 2014 included an increase in fuel cost recovery, partially offset by the timing of vendor payments.

Net cash used for investing activities in 2016 , 2015 , and 2014 totaled $20.0 billion , $7.3 billion , and $6.4 billion , respectively. The cash used for investing activities in 2016 was primarily due to the closing of the Merger, the acquisition of PowerSecure, Southern Company Gas' investment in SNG, the construction of electric generation, transmission, and distribution facilities, the installation of equipment at electric generating facilities to comply with environmental standards, and Southern Power's acquisitions and construction of renewable facilities and a natural gas facility. The cash used for investing activities in 2015 and 2014 was primarily due to gross property additions for installation of equipment at electric generating facilities to comply with environmental standards, construction of electric generation, transmission, and distribution facilities, Southern Power's acquisitions of solar facilities, and purchases of nuclear fuel.

Net cash provided from financing activities totaled $15.7 billion in 2016 primarily due to issuances of long-term debt and common stock associated with completing the Merger and funding the subsidiaries' continuous construction programs, Southern Power's acquisitions, and Southern Company Gas' investment in SNG, partially offset by redemptions of long-term debt and common stock dividend payments. Net cash provided from financing activities totaled $1.7 billion in 2015 due to issuances of long-term debt and common stock and an increase in short-term debt, partially offset by common stock dividend payments and redemptions of long-term debt and preferred and preference stock. Net cash provided from financing activities totaled $644 million in 2014 due to issuances of long-term debt and common stock, partially offset by common stock dividend payments, redemptions of long-term debt, and a reduction in short-term debt. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2016 included an increase of $17.3 billion in total property, plant, and equipment primarily related to the inclusion of Southern Company Gas as a result of the Merger, installation of equipment at electric generating facilities to comply with environmental standards, construction of electric generation, transmission, and distribution facilities, and Southern Power's acquisitions; an increase of $6.2 billion in goodwill related to the acquisitions of Southern Company Gas and PowerSecure; an increase of $1.5 billion in equity investments in unconsolidated subsidiaries primarily related to Southern Company Gas' investment in SNG; an increase of $1.9 billion in other regulatory assets, deferred primarily related to the inclusion of Southern Company Gas as a result of the Merger and changes in ash pond closure strategy, principally for Georgia Power; increases of $17.9 billion in long-term debt and $4.6 billion in total stockholder's equity primarily associated with financing and completing the Merger and to fund the subsidiaries' continuous construction programs and Southern Power's acquisitions; and increases of $1.8 billion in accumulated deferred income taxes and $1.6 billion in other cost of removal obligations primarily related to the inclusion of Southern Company Gas as a result of the Merger. See Notes 1 and 12 to the financial statements for additional information regarding AROs and the Merger, respectively.

At the end of 2016 , the market price of Southern Company's common stock was $49.19 per share (based on the closing price as reported on the New York Stock Exchange) and the book value was $25.00 per share, representing a market-to-book value ratio of 197% , compared to $46.79 , $22.59 , and 207% , respectively, at the end of 2015 .

Southern Company's consolidated ratio of common equity to total capitalization plus short-term debt was 33.3% and 40.5% at December 31, 2016 and 2015, respectively. See Note 6 to the financial statements for additional information.

Sources of Capital

Southern Company intends to meet its future capital needs through operating cash flows, short-term debt, term loans, and external security issuances. Equity capital can be provided from any combination of the Company's stock plans, private placements, or public offerings. The amount and timing of additional equity capital and debt issuances in 2017 , as well as in subsequent years, will be contingent on Southern Company's investment opportunities and the Southern Company system's capital requirements and will depend upon prevailing market conditions and other factors. See " Capital Requirements and Contractual Obligations " herein for additional information.

Except as described herein, the traditional electric operating companies, Southern Power, and Southern Company Gas plan to obtain the funds required for construction and other purposes from operating cash flows, external security issuances, term loans, short-term borrowings, and equity contributions or loans from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

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

Mississippi Power received $245 million of Initial DOE Grants in prior years that were used for the construction of the Kemper IGCC. An additional $25 million of grants from the DOE is expected to be received for commercial operation of the Kemper IGCC. On April 8, 2016, Mississippi Power received approximately $137 million in Additional DOE Grants for the Kemper IGCC, which are expected to be used to reduce future rate impacts for customers. See Note 3 to the financial statements under " Integrated Coal Gasification Combined Cycle " for information regarding legislation related to the securitization of certain costs of the Kemper IGCC.

The issuance of securities by the traditional electric operating companies and Nicor Gas is generally subject to the approval of the applicable state PSC or other applicable state regulatory agency. The issuance of all securities by Mississippi Power and short-term securities by Georgia Power is generally subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, Southern Company and certain of its subsidiaries file registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the appropriate regulatory authorities, as well as the securities registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

Southern Company, each traditional electric operating company, and Southern Power generally obtain financing separately without credit support from any affiliate. In addition, Southern Company Gas Capital obtains external financing for Southern Company Gas and its subsidiaries, other than Nicor Gas, which obtains financing separately without credit support from any affiliates. See Note 6 to the financial statements under " Bank Credit Arrangements " for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of each company are not commingled with funds of any other company in the Southern Company system.

As of December 31, 2016 , Southern Company's current liabilities exceeded current assets by $3.2 billion , primarily due to $2.6 billion of long-term debt that is due within one year, including approximately $0.8 billion at the parent company, $0.6 billion at Alabama Power, $0.5 billion at Georgia Power, $0.1 billion at Gulf Power, and $0.6 billion at Southern Power. To meet short-term cash needs and contingencies, the Southern Company system has substantial cash flow from operating activities and access to capital markets and financial institutions. Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas intend to utilize operating cash flows, as well as commercial paper, lines of credit, bank notes, and securities issuances, as market conditions permit, as well as, under certain circumstances for the traditional electric operating companies, Southern Power, and Southern Company Gas, equity contributions and/or loans from Southern Company to meet their short-term capital needs. In addition, Georgia Power expects to utilize borrowings through the FFB Credit Facility as an additional source of long-term borrowed funds.

At December 31, 2016 , Southern Company and its subsidiaries had approximately $2.0 billion of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2016 were as follows:

	Expires					Executable Term Loans		Expires Within One Year	
Company	2017	2018	2020	Total	Unused	One Year	Two Years	Term Out	No Term Out
	(in millions)			*(in millions)*		*(in millions)*		*(in millions)*	
Southern Company [a]	$ —	$ 1,000	$ 1,250	$ 2,250	$ 2,250	$ —	$ —	$ —	$ —
Alabama Power	35	500	800	1,335	1,335	—	—	—	35
Georgia Power	—	—	1,750	1,750	1,732	—	—	—	—
Gulf Power	85	195	—	280	280	45	—	25	60
Mississippi Power	173	—	—	173	150	—	13	13	160
Southern Power Company [b]	—	—	600	600	522	—	—	—	—
Southern Company Gas [c]	75	1,925	—	2,000	1,949	—	—	—	75
Other	55	—	—	55	55	20	—	20	35
Southern Company Consolidated	$ 423	$ 3,620	$ 4,400	$ 8,443	$ 8,273	$ 65	$ 13	$ 58	$ 365

(a) Represents the Southern Company parent entity.

(b) Excludes credit agreements (Project Credit Facilities) assumed with the acquisition of certain solar facilities, which were non-recourse to Southern Power Company, the proceeds of which were used to finance project costs related to such solar facilities. See Note 12 to the financial statements under " Southern Power " for additional information. Also excludes a $120 million continuing letter of credit facility entered into by Southern Power in December 2016 for standby letters of credit expiring in 2019. At December 31, 2016, the total amount available under the letter of credit facility was $82 million.

(c) Southern Company Gas, as the parent entity, guarantees the obligations of Southern Company Gas Capital, which is the borrower of $1.3 billion of these arrangements. Southern Company Gas' committed credit arrangements also include $700 million for which Nicor Gas is the borrower and which is restricted for working capital needs of Nicor Gas.

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

Most of these bank credit arrangements, as well as the term loan arrangements of Southern Company, Alabama Power, Gulf Power, Mississippi Power, and Southern Power Company, contain covenants that limit debt levels and contain cross acceleration or cross default provisions to other indebtedness (including guarantee obligations) that are restricted only to the indebtedness of the individual company. Such cross default provisions to other indebtedness would trigger an event of default if the applicable borrower defaulted on indebtedness or guarantee obligations over a specified threshold. Such cross acceleration provisions to other indebtedness would trigger an event of default if the applicable borrower defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2016 , Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas were in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

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

A portion of the unused credit with banks is allocated to provide liquidity support to the pollution control revenue bonds of the traditional electric operating companies and the commercial paper programs of Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas. The amount of variable rate pollution control revenue bonds of the traditional electric operating companies outstanding requiring liquidity support as of December 31, 2016 was approximately $1.9 billion . In addition, at December 31, 2016 , the traditional electric operating companies had approximately $423 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. Short-term borrowings are included in notes payable in the balance sheets.

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Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (*)		
	Amount Outstanding	Weighted Average Interest Rate	Average Amount Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2016:					
Commercial paper	**$ 1,909**	**1.1%**	**$ 976**	**0.8%**	**$ 1,970**
Short-term bank debt	**123**	**1.7%**	**176**	**1.7%**	**500**
Total	**$ 2,032**	**1.1%**	**$ 1,152**	**1.1%**	
December 31, 2015:					
Commercial paper	$ 740	0.7%	$ 842	0.4%	$ 1,563
Short-term bank debt	500	1.4%	444	1.1%	795
Total	$ 1,240	0.9%	$ 1,286	0.5%	
December 31, 2014:					
Commercial paper	$ 803	0.3%	$ 754	0.2%	$ 1,582
Short-term bank debt	—	—%	98	0.8%	400
Total	$ 803	0.3%	$ 852	0.3%	

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

In addition to the short-term borrowings in the table above, Southern Power's subsidiary Project Credit Facilities had total amounts outstanding as of December 31, 2016 of $209 million at a weighted average interest rate of 2.1%. For the year ended December 31, 2016 , the Project Credit Facilities had a maximum amount outstanding of $828 million and an average amount outstanding of $566 million at a weighted average interest rate of 2.1%. The amounts outstanding as of December 31, 2016 under the Project Credit Facilities were fully repaid subsequent to December 31, 2016 .

Furthermore, in connection with the acquisition of a solar facility on July 1, 2016, a subsidiary of Southern Power assumed a $217 million construction loan, which was fully repaid in September 2016. During this period, the credit agreement had a maximum amount outstanding of $217 million and an average amount outstanding of $137 million at a weighted average interest rate of 2.2%.

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

Financing Activities

In May and August 2016, Southern Company issued an aggregate of 50.8 million shares of common stock in underwritten offerings for an aggregate purchase price of approximately $2.5 billion. Of the 50.8 million shares, approximately 2.6 million were issued from treasury and the remainder were newly issued shares. The proceeds were used to fund a portion of the consideration for the Merger and related transaction costs, to fund a portion of the purchase price for the SNG investment and related transaction costs, and for other general corporate purposes.

During the fourth quarter 2016, Southern Company issued approximately 8.0 million shares of common stock through at-the-market issuances pursuant to sales agency agreements related to Southern Company's continuous equity offering program and received cash proceeds of approximately $381 million, net of $3 million in fees and commissions.

In addition, during 2016 , Southern Company issued approximately 20 million shares of common stock primarily through employee equity compensation plans and received proceeds of approximately $874 million .

The following table outlines the long-term debt financing activities for Southern Company and its subsidiaries for the year ended December 31, 2016:

Company	Senior Note Issuances	Senior Note Maturities and Redemptions	Revenue Bond Maturities, Redemptions, and Repurchases	Other Long-Term Debt Issuances	Other Long-Term Debt Redemptions and Maturities [(a)]
			(in millions)		
Southern Company [(b)]	$ 8,500	$ 500	$ —	$ 1,350	$ —
Alabama Power	400	200	—	45	—
Georgia Power	650	700	4	425	10
Gulf Power	—	235	—	2	—
Mississippi Power	—	300	—	1,400	653
Southern Power	2,831	200	—	65	86
Southern Company Gas [(c)]	900	420	—	—	—
Other	—	—	—	79	65
Elimination [(d)]	—	—	—	(279)	(228)
Southern Company Consolidated	$ 13,281	$ 2,555	$ 4	$ 3,087	$ 586

(a) Includes reductions in capital lease obligations resulting from cash payments under capital leases.

(b) Represents the Southern Company parent entity.

(c) Reflects only long-term debt financing activities occurring subsequent to completion of the Merger. The senior notes were issued by Southern Company Gas Capital and guaranteed by Southern Company Gas, as the parent entity.

(d) Includes intercompany loans from Southern Company to Mississippi Power and PowerSecure, as well as reductions in affiliate capital lease obligations at Georgia Power. These transactions are eliminated in Southern Company's Consolidated Financial Statements.

In February 2016, Southern Company entered into $700 million notional amount of forward-starting interest rate swaps to hedge exposure to interest rate changes related to anticipated debt issuances. These interest rate swaps were settled in May 2016.

In May 2016, Southern Company issued the following series of senior notes for an aggregate principal amount of $8.5 billion:

- $0.5 billion of 1.55% Senior Notes due July 1, 2018;
- $1.0 billion of 1.85% Senior Notes due July 1, 2019;
- $1.5 billion of 2.35% Senior Notes due July 1, 2021;
- $1.25 billion of 2.95% Senior Notes due July 1, 2023;
- $1.75 billion of 3.25% Senior Notes due July 1, 2026;
- $0.5 billion of 4.25% Senior Notes due July 1, 2036; and
- $2.0 billion of 4.40% Senior Notes due July 1, 2046.

The net proceeds were used to fund a portion of the consideration for the Merger and related transaction costs and for other general corporate purposes.

In September 2016, Southern Company issued $800 million aggregate principal amount of Series 2016A 5.25% Junior Subordinated Notes due October 1, 2076. The proceeds were used to repay short-term indebtedness that was incurred to repay at maturity $500 million aggregate principal amount of Southern Company's Series 2011A 1.95% Senior Notes due September 1, 2016 and for other general corporate purposes.

In December 2016, Southern Company issued $550 million aggregate principal amount of Series 2016B Junior Subordinated Notes due March 15, 2057, which bear interest at a fixed rate of 5.50% per year up to, but not including, March 15, 2022. From, and including, March 15, 2022, the Series 2016B Junior Subordinated Notes will bear interest at a floating rate based on three-month LIBOR. The proceeds were used for general corporate purposes.

Except as described herein, Southern Company's subsidiaries used the proceeds of the debt issuances shown in the table above for their redemptions and maturities shown in the table above, to repay short-term indebtedness, and for general corporate purposes,

including their continuous construction programs and, for Southern Power, its growth strategy. In addition, certain of Georgia Power's and Southern Power's issuances were allocated to eligible renewable energy expenditures.

Georgia Power's "Other Long-Term Debt Issuances" reflected in the table above include borrowings in June and December 2016 under the FFB Credit Facility in an aggregate principal amount of $300 million and $125 million, respectively. The interest rate applicable to the $300 million principal amount is 2.571% and the interest rate applicable to the $125 million principal amount is 3.142%, both for interest periods that extend to the final maturity date of February 20, 2044. The proceeds were used to reimburse Georgia Power for Eligible Project Costs relating to the construction of Plant Vogtle Units 3 and 4.

In June 2016, Southern Power Company issued €600 million aggregate principal amount of Series 2016A 1.00% Senior Notes due June 20, 2022 and €500 million aggregate principal amount of Series 2016B 1.85% Senior Notes due June 20, 2026. The net proceeds are being allocated to renewable energy generation projects. Southern Power Company's obligations under its euro-denominated fixed-rate notes were effectively converted to fixed-rate U.S. dollars at issuance through cross-currency swaps, mitigating foreign currency exchange risk associated with the interest and principal payments. See Note 11 to the financial statements under " Foreign Currency Derivatives " for additional information.

In September 2016, Southern Company Gas Capital issued $350 million aggregate principal amount of 2.45% Senior Notes due October 1, 2023 and $550 million aggregate principal amount of 3.95% Senior Notes due October 1, 2046, both of which are guaranteed by Southern Company Gas. The proceeds were primarily used to repay a $360 million promissory note issued to Southern Company for the purpose of funding a portion of the purchase price for a 50% equity interest in SNG, to fund the purchase of Piedmont Natural Gas Company, Inc.'s interest in SouthStar Energy Services, LLC, to make a voluntary contribution to Southern Company Gas' pension plan, and for general corporate purposes. See Note 12 to the financial statements under " Southern Company – Investment in Southern Natural Gas " and " – Acquisition of Remaining Interest in SouthStar " for additional information.

Subsequent to December 31, 2016, Alabama Power repaid at maturity $200 million aggregate principal amount of its Series 2007A 5.55% Senior Notes due February 1, 2017.

In March 2016, Alabama Power entered into three bank term loan agreements with maturity dates of March 2021, in an aggregate principal amount of $45 million, one of which bears interest at 2.38% per annum and two of which bear interest based on three-month LIBOR.

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

In May 2016, Gulf Power entered into an 11-month floating rate bank loan bearing interest based on one-month LIBOR. This short-term loan was for $100 million aggregate principal amount and the proceeds were used to repay existing indebtedness and for working capital and other general corporate purposes.

In September 2016, Southern Power Company repaid $80 million of an outstanding $400 million floating rate bank loan and extended the maturity date of the remaining $320 million from September 2016 to September 2018. In addition, Southern Power Company entered into a $60 million aggregate principal amount floating rate bank loan bearing interest based on one-month LIBOR due September 2017. The proceeds were used to repay existing indebtedness and for other general corporate purposes.

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

Credit Rating Risk

At December 31, 2016 , Southern Company and its subsidiaries 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 of certain subsidiaries to BBB and/or Baa2 or below. These contracts are for physical electricity and natural gas purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, transmission, interest rate management, foreign currency risk management, and construction of new generation at Plant Vogtle Units 3 and 4.

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

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and/or Baa2	$ 39
At BBB- and/or Baa3	$ 691
At BB+ and/or Ba1 (*)	$ 2,723

(*) Any additional credit rating downgrades at or below BB- and/or Ba3 could increase collateral requirements up to an additional $91 million.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of Southern Company and its subsidiaries to access capital markets and would be likely to impact the cost at which they do so.

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

On May 13, 2016, Moody's downgraded the senior unsecured long-term debt rating of Southern Company to Baa2 from Baa1 and revised the ratings outlook from negative to stable.

On July 11, 2016, S&P raised Southern Company Gas' and Nicor Gas' corporate and senior unsecured long-term debt ratings from BBB+ to A- and revised their ratings outlooks from positive to negative.

On January 10, 2017, S&P revised its consolidated credit rating outlook for Southern Company (including the traditional electric operating companies, Southern Power, and Southern Company Gas) from negative to stable.

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

Market Price Risk

The Southern Company system is exposed to market risks, including commodity price risk, interest rate risk, weather risk, and occasionally foreign currency exchange rate risk. To manage the volatility attributable to these exposures, the applicable company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the applicable company's policies in areas such as counterparty exposure and risk management practices. The Southern Company system's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to a change in interest rates, Southern Company and certain of its subsidiaries enter into derivatives that have been designated as hedges. Derivatives that have been designated as hedges outstanding at December 31, 2016 have a notional amount of $4.0 billion, of which $0.1 billion are to mitigate interest rate volatility related to projected debt financings in 2017 . The remaining $3.9 billion are related to existing fixed and floating rate obligations. The weighted average interest rate on $6.4 billion of long-term variable interest rate exposure at January 1, 2017 was 1.68%. If Southern Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $63 million at January 1, 2017 . See Note 1 to the financial statements under " Financial Instruments " and Note 11 to the financial statements for additional information.

Due to cost-based rate regulation and other various cost recovery mechanisms, the traditional electric operating companies and natural gas distribution utilities continue to have limited exposure to market volatility in interest rates, foreign currency exchange rates, commodity fuel prices, and prices of electricity. In addition, Southern Power's exposure to market volatility in commodity fuel prices and prices of electricity is limited because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of uncontracted generating capacity. To mitigate residual risks relative to movements in electricity prices, the traditional electric operating companies and Southern Power may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases; however, a significant portion of contracts are priced at market. The traditional electric operating companies and certain of the natural gas distribution utilities manage fuel-hedging programs implemented per the guidelines of

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their respective state PSCs or other applicable state regulatory agencies. Southern Company had no material change in market risk exposure for the year ended December 31, 2016 when compared to the year ended December 31, 2015 .

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

	2016 Changes	2015 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (213)**	$ (188)
Acquisitions	**(54)**	—
Contracts realized or settled	**141**	142
Current period changes (*)	**171**	(167)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ 45**	$ (213)

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

The net hedge volumes of energy-related derivative contracts were 500 million mmBtu and 224 million mmBtu for the years ended December 31, 2016 and 2015 , respectively.

For the traditional electric operating companies and Southern Power, the weighted average swap contract cost above or (below) market prices was approximately $(0.05) per mmBtu as of December 31, 2016 and $1.14 per mmBtu as of December 31, 2015 . The majority of the natural gas hedge gains and losses are recovered through the traditional electric operating companies' fuel cost recovery clauses.

At December 31, 2016 and 2015 , substantially all of the Southern Company system's energy-related derivative contracts were designated as regulatory hedges and were related to the applicable company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the energy cost recovery clause. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges, are initially deferred in OCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Southern Company system uses exchange-traded market-observable contracts, which are categorized as Level 1 of the fair value hierarchy, and 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 at December 31, 2016 were as follows:

	Fair Value Measurements December 31, 2016			
	Total Fair Value	Maturity		
		Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ (7)	$ 15	$ (15)	$ (7)
Level 2	52	52	(7)	7
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ 45	$ 67	$ (22)	$ —

The Southern Company system is exposed to market price risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. The Southern Company system 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 Southern Company system does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under " Financial Instruments " and Note 11 to the financial statements.

Southern Company performs periodic reviews of its leveraged lease transactions, both domestic and international, and the creditworthiness of the lessees, including a review of the value of the underlying leased assets and the credit ratings of the lessees. Southern Company's domestic lease transactions generally do not have any credit enhancement mechanisms; however, the lessees in its international lease transactions have pledged various deposits as additional security to secure the obligations. The lessees in the Company's international lease transactions are also required to provide additional collateral in the event of a credit downgrade below a certain level.

Capital Requirements and Contractual Obligations

The Southern Company system's construction program is currently estimated to total approximately $9.1 billion for 2017 , $8.2 billion for 2018 , $7.3 billion for 2019 , $6.9 billion for 2020 , and $6.4 billion for 2021 . These amounts include expenditures of approximately $0.7 billion, $0.5 billion, $0.3 billion, and $0.1 billion for the construction of Plant Vogtle Units 3 and 4 in 2017, 2018, 2019, and 2020, respectively, $0.3 billion for the construction of the Kemper IGCC in 2017, and $1.5 billion per year for 2017 through 2021 for acquisitions and/or construction of new Southern Power generating facilities. These amounts also include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these amounts are $0.9 billion , $0.7 billion , $0.3 billion , $0.4 billion , and $0.6 billion for 2017 , 2018 , 2019 , 2020 , and 2021 , respectively. These estimated expenditures do not include potential compliance costs that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from existing, new, modified, or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – " Environmental Matters – Environmental Statutes and Regulations " and "– Global Climate Issues " herein for additional information.

The traditional electric operating companies also anticipate costs associated with closure and monitoring of ash ponds in accordance with the CCR Rule, which are reflected in the Company's ARO liabilities. These costs, which could change as the Southern Company system continues to refine its assumptions underlying the cost estimates and evaluate the method and timing of compliance activities, are estimated to be approximately $0.4 billion, $0.3 billion, $0.3 billion, $0.4 billion, and $0.4 billion for 2017 , 2018 , 2019 , 2020 , and 2021 , respectively. See Note 1 to the financial statements under " Asset Retirement Obligations and Other Costs of Removal " for additional information.

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in electric generating plants, including unit retirements and replacements and adding or changing fuel sources at existing electric generating units, to meet regulatory requirements; changes in FERC rules and regulations; state regulatory agency approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. Additionally, planned expenditures for plant acquisitions may vary due to market opportunities and Southern Power's ability to execute its growth strategy. See Note 12 to the financial statements under " Southern Power " for additional information regarding Southern Power's plant acquisitions.

In addition, the construction program includes the development and construction of new electric generating facilities with designs that have not been finalized or previously constructed, including first-of-a-kind technology, which may result in revised estimates during construction. See Note 3 to the financial statements under " Regulatory Matters – Georgia Power – Nuclear Construction " and " Integrated Coal Gasification Combined Cycle " for information regarding additional factors that may impact construction expenditures.

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

In addition, as discussed in Note 2 to the financial statements, Southern Company provides postretirement benefits to the majority of its employees and funds trusts to the extent required by PSCs, other applicable state regulatory agencies, or the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, unrecognized tax benefits, pipeline charges, storage capacity, gas supply, asset management agreements, standby letters of credit and performance/surety bonds, other purchase commitments, and trusts are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

The Southern Company system's contractual obligations at December 31, 2016 were as follows:

	2017	2018-2019	2020-2021	After 2021	Total
			(in millions)		
Long-term debt [(a)] —					
Principal	$ 2,556	$ 7,025	$ 4,448	$ 30,890	$ 44,919
Interest	1,635	3,034	2,592	24,055	31,316
Preferred and preference stock dividends [(b)]	45	91	91	—	227
Financial derivative obligations [(c)]	516	101	12	1	630
Operating leases [(d)]	152	247	190	1,195	1,784
Capital leases [(d)]	16	32	22	79	149
Unrecognized tax benefits [(e)]	484	—	—	—	484
Pipeline charges, storage capacity, and gas supply [(f)]	822	1,049	746	2,591	5,208
Asset management agreements [(g)]	10	7	—	—	17
Standby letters of credit, performance/surety bonds [(h)]	85	1	—	—	86
Purchase commitments —					
Capital [(i)]	8,797	14,649	12,055	—	35,501
Fuel [(j)]	3,763	4,379	2,248	7,095	17,485
Purchased power [(k)]	362	753	782	2,651	4,548
Other [(l)]	479	560	777	3,024	4,840
Trusts —					
Nuclear decommissioning [(m)]	5	11	11	99	126
Pension and other postretirement benefit plans [(n)]	146	293	—	—	439
Total	$ 19,873	$ 32,232	$ 23,974	$ 71,680	$ 147,759

(a) All amounts are reflected based on final maturity dates except for amounts related to FFB borrowings. As it relates to the FFB borrowings, the final maturity date is February 20, 2044; however, principal amortization is reflected beginning in 2020. See Note 6 to the financial statements under " DOE Loan Guarantee Borrowings " for additional information. Southern Company and its subsidiaries plan to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 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 principal for 2017 includes $40 million of pollution control revenue bonds that are classified on the balance sheet at December 31, 2016 as short-term since they are variable rate demand obligations that are supported by short-term credit facilities; however, the final maturity date is in 2028 . Long-term debt excludes capital lease amounts (shown separately).

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

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

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

(e) See Note 5 to the financial statements under " Unrecognized Tax Benefits " for additional information.

(f) Includes charges recoverable through a natural gas cost recovery mechanism, or alternatively billed to marketers selling retail natural gas, and demand charges associated with Southern Company Gas' wholesale gas services. The gas supply balance includes amounts for gas commodity purchase commitments associated with Southern Company Gas' gas marketing services of 33 million mmBtu at floating gas prices calculated using forward natural gas prices at December 31, 2016 and valued at $106 million . Southern Company Gas provides guarantees to certain gas suppliers for certain of its subsidiaries in support of payment obligations.

(g) Represents fixed-fee minimum payments for asset management agreements associated with wholesale gas services.

(h) Guarantees are provided to certain municipalities and other agencies and certain natural gas suppliers in support of payment obligations.

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

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

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

(l) Includes long-term service agreements, contracts for the procurement of limestone, contractual environmental remediation liabilities, and operation and maintenance agreements. Long-term service agreements include price escalation based on inflation indices.

(m) Projections of nuclear decommissioning trust fund contributions for Plant Hatch and Plant Vogtle Units 1 and 2 are based on the 2013 ARP for Georgia Power. Alabama Power also has external trust funds for nuclear decommissioning costs; however, Alabama Power currently has no additional funding requirements. See Note 1 to the financial statements under "Nuclear Decommissioning" for additional information.

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

Cautionary Statement Regarding Forward-Looking Statements

Southern Company's 2016 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning regulated rates, the strategic goals for the wholesale business, 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 s, postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, completion dates of construction projects, filings with state and federal regulatory authorities, impact of the PATH Act, federal income tax benefits, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws regulating emissions, discharges, and disposal to air, water, and land , and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, including potential tax reform legislation, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries ;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity and natural gas, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of natural gas and other fuels;
- limits on pipeline capacity;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development , construction, and operation of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor , sustaining nitrogen supply, contractor or supplier delay, non-performance under construction, operating, or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by any PSC);
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any environmental performance standards and the requirements of tax credits and other incentives , and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of the Southern Company system's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- ongoing renewable energy partnerships and development agreements;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions;
- actions related to cost recovery for the Kemper IGCC, including the ultimate impact of the 2015 decision of the Mississippi Supreme Court, the Mississippi PSC's December 2015 rate order, and related legal or regulatory proceedings, Mississippi PSC review of the prudence of Kemper IGCC costs and approval of further permanent rate recovery plans, actions relating to proposed securitization, satisfaction of requirements to utilize grants, and the ultimate impact of the termination of the proposed sale of an interest in the Kemper IGCC to SMEPA;

- the ability to successfully operate the electric utilities' generating, transmission, and distribution facilities and Southern Company Gas' natural gas distribution and storage facilities and the successful performance of necessary corporate functions;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- the inherent risks involved in transporting and storing natural gas;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the possibility that the anticipated benefits from the Merger cannot be fully realized or may take longer to realize than expected, the possibility that costs related to the integration of Southern Company and Southern Company Gas will be greater than expected, the ability to retain and hire key personnel and maintain relationships with customers, suppliers, or other business partners, and the diversion of management time on integration-related issues;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Southern Company system's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in Southern Company's and any of its subsidiaries' credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general , as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of Southern Company's electric utilities 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 Southern Company system's business resulting from incidents affecting the U.S. electric grid , natural gas pipeline infrastructure , or operation of generating or storage resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by Southern Company from time to time with the SEC.

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

CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2016 , 2015 , and 2014
Southern Company and Subsidiary Companies 2016 Annual Report

	2016	2015	2014
		(in millions)	
Operating Revenues:			
Retail electric revenues	**$ 15,234**	$ 14,987	$ 15,550
Wholesale electric revenues	**1,926**	1,798	2,184
Other electric revenues	**698**	657	672
Natural gas revenues	**1,596**	—	—
Other revenues	**442**	47	61
Total operating revenues	**19,896**	17,489	18,467
Operating Expenses:			
Fuel	**4,361**	4,750	6,005
Purchased power	**750**	645	672
Cost of natural gas	**613**	—	—
Cost of other sales	**260**	—	—
Other operations and maintenance	**5,240**	4,416	4,354
Depreciation and amortization	**2,502**	2,034	1,945
Taxes other than income taxes	**1,113**	997	981
Estimated loss on Kemper IGCC	**428**	365	868
Total operating expenses	**15,267**	13,207	14,825
Operating Income	**4,629**	4,282	3,642
Other Income and (Expense):			
Allowance for equity funds used during construction	**202**	226	245
Earnings from equity method investments	**59**	—	—
Interest expense, net of amounts capitalized	**(1,317)**	(840)	(835)
Other income (expense), net	**(93)**	(39)	(44)
Total other income and (expense)	**(1,149)**	(653)	(634)
Earnings Before Income Taxes	**3,480**	3,629	3,008
Income taxes	**951**	1,194	977
Consolidated Net Income	**2,529**	2,435	2,031
Less:			
Dividends on preferred and preference stock of subsidiaries	**45**	54	68
Net income attributable to noncontrolling interests	**36**	14	—
Consolidated Net Income Attributable to Southern Company	**$ 2,448**	$ 2,367	$ 1,963
Common Stock Data:			
Earnings per share (EPS) —			
Basic EPS	**$ 2.57**	$ 2.60	$ 2.19
Diluted EPS	**2.55**	2.59	2.18
Average number of shares of common stock outstanding — (in millions)			
Basic	**951**	910	897
Diluted	**958**	914	901

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2016 , 2015 , and 2014
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	2016	2015	2014
		(in millions)	
Consolidated Net Income	**$ 2,529**	$ 2,435	$ 2,031
Other comprehensive income:			
Qualifying hedges:			
Changes in fair value, net of tax of $(84), $(8), and $(6), respectively	**(136)**	(13)	(10)
Reclassification adjustment for amounts included in net income, net of tax of $43, $4, and $3, respectively	**69**	6	5
Pension and other postretirement benefit plans:			
Benefit plan net gain (loss), net of tax of $10, $(1), and $(32), respectively	**13**	(2)	(51)
Reclassification adjustment for amounts included in net income, net of tax of $3, $4, and $2, respectively	**4**	7	3
Total other comprehensive income (loss)	**(50)**	(2)	(53)
Less:			
Dividends on preferred and preference stock of subsidiaries	**45**	54	68
Comprehensive income attributable to noncontrolling interests	**36**	14	—
Consolidated Comprehensive Income Attributable to Southern Company	**$ 2,398**	$ 2,365	$ 1,910

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2016 , 2015 , and 2014
Southern Company and Subsidiary Companies 2016 Annual Report

	2016	2015	2014
		(in millions)	
Operating Activities:			
Consolidated net income	$ **2,529**	$ 2,435	$ 2,031
Adjustments to reconcile consolidated net income to net cash provided from operating activities —			
Depreciation and amortization, total	**2,923**	2,395	2,293
Deferred income taxes	**(127)**	1,404	709
Collateral deposits	**(102)**	—	—
Allowance for equity funds used during construction	**(202)**	(226)	(245)
Pension, postretirement, and other employee benefits	**(65)**	83	(9)
Pension and postretirement funding	**(1,029)**	(7)	(506)
Settlement of asset retirement obligations	**(171)**	(37)	(17)
Stock based compensation expense	**121**	99	63
Hedge settlements	**(233)**	(17)	—
Estimated loss on Kemper IGCC	**428**	365	868
Income taxes receivable, non-current	**(122)**	(413)	—
Other, net	**(36)**	(33)	13
Changes in certain current assets and liabilities —			
-Receivables	**(544)**	243	(352)
-Fossil fuel for generation	**178**	61	408
-Natural gas for sale	**(226)**	—	—
-Materials and supplies	**(31)**	(44)	(67)
-Other current assets	**(174)**	(108)	(57)
-Accounts payable	**301**	(353)	267
-Accrued taxes	**1,456**	352	(105)
-Accrued compensation	**36**	(41)	255
-Retail fuel cost over recovery — short-term	**(231)**	289	(23)
-Mirror CWIP	**—**	(271)	180
-Other current liabilities	**215**	98	109
Net cash provided from operating activities	**4,894**	6,274	5,815
Investing Activities:			
Business acquisitions, net of cash acquired	**(10,689)**	(1,719)	(731)
Property additions	**(7,310)**	(5,674)	(5,246)
Investment in restricted cash	**(733)**	(160)	(11)
Distribution of restricted cash	**742**	154	57
Nuclear decommissioning trust fund purchases	**(1,160)**	(1,424)	(916)
Nuclear decommissioning trust fund sales	**1,154**	1,418	914
Cost of removal, net of salvage	**(245)**	(167)	(170)
Change in construction payables, net	**(121)**	402	(107)
Investment in unconsolidated subsidiaries	**(1,444)**	—	—
Prepaid long-term service agreement	**(134)**	(197)	(181)
Other investing activities	**(108)**	87	(17)
Net cash used for investing activities	**(20,048)**	(7,280)	(6,408)
Financing Activities:			
Increase (decrease) in notes payable, net	**1,228**	73	(676)
Proceeds —			
Long-term debt	**16,368**	7,029	3,169
Interest-bearing refundable deposit	**—**	—	125
Common stock	**3,758**	256	806
Short-term borrowings	**—**	755	—

Redemptions and repurchases —						
Long-term debt		**(3,145)**		(3,604)		(816)
Common stock		**—**		(115)		(5)
Interest-bearing refundable deposits		**—**		(275)		—
Preferred and preference stock		**—**		(412)		—
Short-term borrowings		**(478)**		(255)		—
Distributions to noncontrolling interests		**(72)**		(18)		(1)
Capital contributions from noncontrolling interests		**682**		341		8
Purchase of membership interests from noncontrolling interests		**(129)**		—		—
Payment of common stock dividends		**(2,104)**		(1,959)		(1,866)
Other financing activities		**(383)**		(116)		(100)
Net cash provided from financing activities		**15,725**		1,700		644
Net Change in Cash and Cash Equivalents		**571**		694		51
Cash and Cash Equivalents at Beginning of Year		**1,404**		710		659
Cash and Cash Equivalents at End of Year	**$**	**1,975**	$	1,404	$	710

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2016 and 2015
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Assets	**2016**	2015
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 1,975**	$ 1,404
Receivables —		
Customer accounts receivable	**1,565**	1,058
Energy marketing receivable	**623**	—
Unbilled revenues	**706**	397
Under recovered regulatory clause revenues	**18**	63
Income taxes receivable, current	**544**	144
Other accounts and notes receivable	**377**	398
Accumulated provision for uncollectible accounts	**(43)**	(13)
Materials and supplies	**1,462**	1,061
Fossil fuel for generation	**689**	868
Natural gas for sale	**631**	—
Prepaid expenses	**364**	495
Other regulatory assets, current	**581**	580
Other current assets	**230**	71
Total current assets	**9,722**	6,526
Property, Plant, and Equipment:		
In service	**98,416**	75,118
Less accumulated depreciation	**29,852**	24,253
Plant in service, net of depreciation	**68,564**	50,865
Other utility plant, net	**—**	233
Nuclear fuel, at amortized cost	**905**	934
Construction work in progress	**8,977**	9,082
Total property, plant, and equipment	**78,446**	61,114
Other Property and Investments:		
Goodwill	**6,251**	2
Equity investments in unconsolidated subsidiaries	**1,549**	6
Other intangible assets, net of amortization of $62 and $12 at December 31, 2016 and December 31, 2015, respectively	**970**	317
Nuclear decommissioning trusts, at fair value	**1,606**	1,512
Leveraged leases	**774**	755
Miscellaneous property and investments	**270**	160
Total other property and investments	**11,420**	2,752
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**1,629**	1,560
Unamortized loss on reacquired debt	**223**	227
Other regulatory assets, deferred	**6,851**	4,989
Income taxes receivable, non-current	**11**	413
Other deferred charges and assets	**1,395**	737
Total deferred charges and other assets	**10,109**	7,926
Total Assets	**$ 109,697**	$ 78,318

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2016 and 2015
Southern Company and Subsidiary Companies 2016 Annual Report

Liabilities and Stockholders' Equity	2016	2015
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 2,587**	$ 2,674
Notes payable	**2,241**	1,376
Energy marketing trade payables	**597**	—
Accounts payable	**2,228**	1,905
Customer deposits	**558**	404
Accrued taxes —		
Accrued income taxes	**193**	9
Unrecognized tax benefits	**385**	10
Other accrued taxes	**667**	484
Accrued interest	**518**	249
Accrued compensation	**915**	777
Asset retirement obligations, current	**378**	217
Liabilities from risk management activities, net of collateral	**107**	156
Acquisitions payable	**489**	—
Other regulatory liabilities, current	**236**	278
Over recovered regulatory clause revenues, current	**135**	106
Other current liabilities	**683**	484
Total current liabilities	**12,917**	9,129
Long-Term Debt (See accompanying statements)	**42,629**	24,688
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**14,092**	12,322
Deferred credits related to income taxes	**219**	187
Accumulated deferred investment tax credits	**2,228**	1,219
Employee benefit obligations	**2,299**	2,582
Asset retirement obligations, deferred	**4,136**	3,542
Unrecognized tax benefits, deferred	**—**	370
Accrued environmental remediation	**397**	42
Other cost of removal obligations	**2,748**	1,162
Other regulatory liabilities, deferred	**258**	254
Other deferred credits and liabilities	**880**	678
Total deferred credits and other liabilities	**27,257**	22,358
Total Liabilities	**82,803**	56,175
Redeemable Preferred Stock of Subsidiaries (See accompanying statements)	**118**	118
Redeemable Noncontrolling Interests (See accompanying statements)	**164**	43
Total Stockholders' Equity (See accompanying statements)	**26,612**	21,982
Total Liabilities and Stockholders' Equity	**$ 109,697**	$ 78,318
Commitments and Contingent Matters (See notes)		

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION
At December 31, 2016 and 2015
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		2016	2015	**2016**	2015
			(in millions)		*(percent of total)*
Long-Term Debt:					
Long-term debt payable to affiliated trusts —					
Variable rate (3.95% at 1/1/17) due 2042		**$ 206**	$ 206		
Long-term senior notes and debt —					
Maturity	Interest Rates				
2016	1.95% to 5.30%	**—**	1,360		
2017	1.30% to 7.20%	**2,019**	1,995		
2018	1.50% to 5.40%	**2,353**	1,697		
2019	1.85% to 5.55%	**3,076**	1,176		
2020	2.38% to 4.75%	**1,326**	1,327		
2021	2.35% to 9.10%	**2,655**	200		
2022 through 2051	1.00% to 8.70%	**21,797**	10,972		
Variable rates (0.76% to 3.50% at 1/1/16) due 2016		**—**	1,278		
Variable rates (1.82% to 3.75% at 1/1/17) due 2017		**461**	400		
Variable rates (1.88% to 2.24% at 1/1/17) due 2018		**1,520**	—		
Variable rates (1.87% to 2.10% at 1/1/17) due 2021		**25**	—		
Variable rate (3.75% at 1/1/17) due 2032 to 2036		**15**	13		
Total long-term senior notes and debt		**35,247**	20,418		
Other long-term debt —					
Pollution control revenue bonds —					
Maturity	Interest Rates				
2019	4.55%	**25**	25		
2022 through 2049	0.65% to 5.15%	**1,429**	1,509		
Variable rate (0.22% at 1/1/16) due 2016		**—**	4		
Variable rates (0.77% to 0.87% at 1/1/17) due 2017		**76**	76		
Variable rates (0.82% to 0.86% at 1/1/17) due 2021		**65**	65		
Variable rates (0.75% to 0.87% at 1/1/17) due 2022 to 2053		**1,739**	1,659		
Plant Daniel revenue bonds (7.13%) due 2021		**270**	270		
FFB loans —					
2.57% to 3.86% due 2020		**44**	37		
2.57% to 3.86% due 2021		**44**	37		
2.57% to 3.86% due 2022 to 2044		**2,537**	2,126		
First mortgage bonds —					
4.70% due 2019		**50**	—		
2.66% to 6.58% due 2023 to 2038		**575**	—		
Gas facility revenue bonds —					
Variable rate (1.28% at 1/1/17) due 2022 to 2033		**200**	—		
Junior subordinated notes (5.25% to 6.25%) due 2057 to 2076		**2,350**	1,000		
Total other long-term debt		**9,404**	6,808		
Unamortized fair value adjustment of long-term debt		**578**	—		
Capitalized lease obligations		**136**	146		
Unamortized debt premium		**52**	61		
Unamortized debt discount		**(194)**	(36)		
Unamortized debt issuance expense		**(213)**	(241)		
Total long-term debt (annual interest requirement — $1.6 billion)		**45,216**	27,362		
Less amount due within one year		**2,587**	2,674		
Long-term debt excluding amount due within one year		**42,629**	24,688	**61.3%**	52.6%

CONSOLIDATED STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2016 and 2015
Southern Company and Subsidiary Companies 2016 Annual Report

	2016	2015	2016	2015
		(in millions)		*(percent of total)*
Redeemable Preferred Stock of Subsidiaries:				
Cumulative preferred stock				
$100 par or stated value — 4.20% to 5.44%				
Authorized — 20 million shares				
Outstanding — 1 million shares	**81**	81		
$1 par value — 5.83%				
Authorized — 28 million shares				
Outstanding — 2 million shares: $25 stated value	**37**	37		
Total redeemable preferred stock of subsidiaries (annual dividend requirement — $6 million)	**118**	118	**0.2**	0.3
Redeemable Noncontrolling Interests	**164**	43	**0.2**	0.1
Common Stockholders' Equity:				
Common stock, par value $5 per share —	**4,952**	4,572		
Authorized — 1.5 billion shares				
Issued — 2016: 991 million shares				
— 2015: 915 million shares				
Treasury — 2016: 0.8 million shares				
— 2015: 3.4 million shares				
Paid-in capital	**9,661**	6,282		
Treasury, at cost	**(31)**	(142)		
Retained earnings	**10,356**	10,010		
Accumulated other comprehensive loss	**(180)**	(130)		
Total common stockholders' equity	**24,758**	20,592	**35.6**	44.0
Preferred and Preference Stock of Subsidiaries and Noncontrolling Interests:				
Non-cumulative preferred stock				
$25 par value — 6.00% to 6.13%				
Authorized — 60 million shares				
Outstanding — 2 million shares	**45**	45		
Preference stock				
Authorized — 65 million shares				
Outstanding — $1 par value	**196**	196		
— 6.45% to 6.50% — 8 million shares (non-cumulative)				
Outstanding — $100 par or stated value	**368**	368		
— 5.60% to 6.50% — 4 million shares (non-cumulative)				
Noncontrolling interests	**1,245**	781		
Total preferred and preference stock of subsidiaries and noncontrolling interests (annual dividend requirement — $39 million)	**1,854**	1,390	**2.7**	3.0
Total stockholders' equity	**26,612**	21,982		
Total Capitalization	**$ 69,523**	$ 46,831	**100.0%**	100.0%

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

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2016 , 2015 , and 2014
Southern Company and Subsidiary Companies 2016 Annual Report

	Southern Company Common Stockholders' Equity									
	Number of Common Shares		Common Stock							
	Issued	Treasury	Par Value	Paid-In Capital	Treasury	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Preferred and Preference Stock of Subsidiaries	Noncontrolling Interests	Total
	(in thousands)		*(in millions)*							
Balance at December 31, 2013	892,733	(5,647)	$4,461	$ 5,362	$ (250)	$ 9,510	$ (75)	$ 756	$ —	$ 19,764
Consolidated net income attributable to Southern Company	—	—	—	—	—	1,963	—	—	—	1,963
Other comprehensive income (loss)	—	—	—	—	—	—	(53)	—	—	(53)
Stock issued	15,769	4,996	78	501	227	—	—	—	—	806
Stock-based compensation	—	—	—	86	—	—	—	—	—	86
Cash dividends of $2.0825 per share	—	—	—	—	—	(1,866)	—	—	—	(1,866)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	—	221	221
Net loss attributable to noncontrolling interests	—	—	—	—	—	—	—	—	(2)	(2)
Other	—	(74)	—	6	(3)	2	—	—	2	7
Balance at December 31, 2014	908,502	(725)	4,539	5,955	(26)	9,609	(128)	756	221	20,926
Consolidated net income attributable to Southern Company	—	—	—	—	—	2,367	—	—	—	2,367
Other comprehensive income (loss)	—	—	—	—	—	—	(2)	—	—	(2)
Stock issued	6,571	(2,599)	33	223	—	—	—	—	—	256
Stock-based compensation	—	—	—	100	—	—	—	—	—	100
Stock repurchased, at cost	—	—	—	—	(115)	—	—	—	—	(115)
Cash dividends of $2.1525 per share	—	—	—	—	—	(1,959)	—	—	—	(1,959)
Preference stock redemptions	—	—	—	—	—	—	—	(150)	—	(150)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	—	567	567
Distributions to noncontrolling interests	—	—	—	—	—	—	—	—	(18)	(18)
Net income attributable to noncontrolling interests	—	—	—	—	—	—	—	—	12	12
Other	—	(28)	—	4	(1)	(7)	—	3	(1)	(2)
Balance at December 31, 2015	**915,073**	**(3,352)**	**4,572**	**6,282**	**(142)**	**10,010**	**(130)**	**609**	**781**	**21,982**
Consolidated net income attributable to Southern Company	**—**	**—**	**—**	**—**	**—**	**2,448**	**—**	**—**	**—**	**2,448**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**—**	**—**	**(50)**	**—**	**—**	**(50)**
Stock issued	**76,140**	**2,599**	**380**	**3,263**	**115**	**—**	**—**	**—**	**—**	**3,758**
Stock-based compensation	**—**	**—**	**—**	**120**	**—**	**—**	**—**	**—**	**—**	**120**
Cash dividends of $2.2225 per share	**—**	**—**	**—**	**—**	**—**	**(2,104)**	**—**	**—**	**—**	**(2,104)**
Contributions from noncontrolling interests	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**618**	**618**
Distributions to noncontrolling interests	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(57)**	**(57)**
Purchase of membership interests from noncontrolling interests	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(129)**	**(129)**
Net income attributable to redeemable noncontrolling interests	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**32**	**32**
Other	**—**	**(66)**	**—**	**(4)**	**(4)**	**2**	**—**	**—**	**—**	**(6)**
Balance at December 31, 2016	**991,213**	**(819)**	**$4,952**	**$ 9,661**	**$ (31)**	**$ 10,356**	**$ (180)**	**$ 609**	**$ 1,245**	**$ 26,612**

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

NOTES TO FINANCIAL STATEMENTS
Southern Company and Subsidiary Companies 2016 Annual Report

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

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

The financial statements reflect Southern Company's investments in the subsidiaries on a consolidated basis. The equity method is used for entities in which the Company has significant influence but does not control and for variable interest entities where the Company has an equity investment but is not the primary beneficiary. Intercompany transactions have been eliminated in consolidation.

The traditional electric operating companies, Southern Power, certain subsidiaries of Southern Company Gas, and certain other subsidiaries are subject to regulation by the FERC, and the traditional electric operating companies and natural gas distribution utilities are also subject to regulation by their respective state PSCs or other applicable state regulatory agencies. As such, the consolidated financial statements reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by relevant state PSCs or other applicable state regulatory agencies. 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. These reclassifications had no impact on Southern Company's results of operations, financial position, or cash flows.

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

Recently Issued Accounting Standards

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

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

Southern Company's ongoing evaluation of other revenue streams and related contracts includes longer term contractual commitments and unregulated sales to customers. Some revenue arrangements, such as certain PPAs and alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on Southern Company's financial statements. In addition, the power and utilities industry is currently addressing other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). If

final implementation guidance indicates CIAC will be accounted for under ASC 606 and offsetting regulatory treatment is not permitted, it could have a material impact on Southern Company's financial statements.

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

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

On March 30, 2016, the FASB issued ASU No. 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, Southern 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. Southern 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. Southern 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 Southern Company. See Notes 5, 8, and 14 for disclosures impacted by ASU 2016-09.

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

On November 17, 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* (ASU 2016-18). ASU 2016-18 eliminates the need to reflect transfers between cash and restricted cash in operating, investing, and financing activities in the statement of cash flows. Upon adoption, the net change in cash and cash equivalents during the period will include amounts generally described as restricted cash or restricted cash equivalents. ASU 2016-18 is effective for fiscal years beginning after December 15, 2017, with early adoption permitted, and will be applied retrospectively to each period presented. Southern Company does not intend to adopt the guidance early. The adoption of ASU 2016-18 will not have a material impact on the financial statements of Southern Company.

Regulatory Assets and Liabilities

The traditional electric operating companies and natural gas distribution utilities are 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.

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

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

	2016	2015	Note
	(in millions)		
Retiree benefit plans	**$ 3,959**	$ 3,440	(a,n)
Deferred income tax charges	**1,590**	1,514	(b)
Asset retirement obligations-asset	**1,080**	481	(b,n)
Environmental remediation-asset	**491**	78	(j,n)
Other regulatory assets	**355**	299	(k)
Remaining net book value of retired assets	**351**	283	(o)
Under recovered regulatory clause revenues	**273**	142	(g)
Loss on reacquired debt	**243**	248	(c)
Property damage reserves-asset	**206**	92	(i)
Kemper IGCC	**201**	216	(h)
Vacation pay	**182**	178	(f,n)
Long-term debt fair value adjustment	**155**	—	(p)
Deferred PPA charges	**141**	163	(e,n)
Nuclear outage	**97**	88	(g)
Fuel-hedging-asset	**35**	225	(d,n)
Other cost of removal obligations	**(2,774)**	(1,177)	(b)
Deferred income tax credits	**(219)**	(187)	(b)
Over recovered regulatory clause revenues	**(203)**	(261)	(g)
Property damage reserves-liability	**(177)**	(178)	(l)
Other regulatory liabilities	**(110)**	(35)	(m)
Asset retirement obligations-liability	**(10)**	(45)	(b,n)
Total regulatory assets (liabilities), net	**$ 5,866**	$ 5,564	

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

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

(b) Asset retirement and other cost of removal obligations are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 70 years . Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(c) Recovered over either the remaining life of the original issue or, if refinanced, over the remaining life of the new issue, which may range up to 50 years .

(d) Recorded over the life of the underlying hedged purchase contracts, which generally do not exceed five years . Upon final settlement, actual costs incurred are recovered through fuel and energy cost recovery mechanisms.

(e) Recovered over the life of the PPA for periods up to seven years .

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

(g) Recorded and recovered or amortized as approved or accepted by the appropriate state PSCs or other applicable regulatory agencies over periods generally not exceeding ten years .

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

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

(j) Recovered through environmental cost recovery mechanisms when the remediation is performed or the work is performed.

(k) Comprised of numerous immaterial components including deferred income tax charges - Medicare subsidy, cancelled construction projects, building and generating plant leases, property tax, and other miscellaneous assets. These costs are recorded and recovered or amortized as approved by the appropriate state PSCs over periods generally not exceeding 50 years .

(l) Recovered as storm restoration and potential reliability-related expenses are incurred as approved by the appropriate state PSCs.

(m) Comprised of numerous immaterial components including retiree benefit plans, fuel-hedging gains, and other liabilities that are recorded and recovered or amortized as approved by the appropriate state PSCs or other applicable regulatory agencies generally over periods not exceeding 4 years .

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

(o) Amortized as approved by the appropriate state PSCs over periods generally up to 11 years .

(p) Recorded in relation to the Merger. Recovered over the remaining life of the original debt issuances, which range up to 22 years . For additional information see Note 12 under " Southern Company – Merger with Southern Company Gas ."

In the event that a portion of a traditional electric operating company's or a natural gas distribution utility's operations is no longer subject to applicable accounting rules for rate regulation, such company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition,

the traditional electric operating company or natural gas distribution utility 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 " Regulatory Matters – Alabama Power ," " Regulatory Matters – Georgia Power ," " Regulatory Matters – Gulf Power ," " Regulatory Matters – Southern Company Gas ," and " Integrated Coal Gasification Combined Cycle " for additional information.

Revenues

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amount billable under the contract terms. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Retail rates for the traditional electric operating companies and natural gas distribution utilities may include provisions to adjust billings for fluctuations in fuel and purchased gas costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors.

Southern Company's electric utility subsidiaries and Southern Company Gas have a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel.

Income and Other Taxes

Southern Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income. In accordance with regulatory requirements, deferred federal ITCs for the traditional electric operating companies and Southern Company Gas are amortized over the average lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Under current tax law, certain projects at Southern Power are eligible for federal ITCs or cash grants. Southern Power has elected to receive ITCs. The credits are recorded as a deferred credit and are amortized to income tax expense over the life of the asset. Furthermore, the tax basis of the asset is reduced by 50% of the credits received, resulting in a net deferred tax asset. Southern Power has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation. In addition, certain projects are eligible for federal PTCs, which are recorded to income tax expense based on KWH production.

Federal ITCs and PTCs, as well as state ITCs and other state tax credits available to reduce income taxes payable, were not fully utilized in 2016 and will be carried forward and utilized in future years. In addition, Southern Company is expected to have a consolidated federal net operating loss (NOL) carryforward for the 2016 tax year along with various state NOL carryforwards, which could result in income tax benefits in the future, if utilized. See Note 5 under " Current and Deferred Income Taxes – Tax Credit Carryforwards " and " – Net Operating Loss " for additional information.

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

Property, Plant, and Equipment

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

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

	2016	2015
	(in millions)	
Electric utilities:		
Generation	**$ 48,836**	$ 41,648
Transmission	**11,156**	10,544
Distribution	**18,418**	17,670
General	**4,629**	4,377
Plant acquisition adjustment	**126**	123
Electric utility plant in service	**83,165**	74,362
Natural gas distribution utilities:		
Transportation and distribution	**11,996**	—
Utility plant in service	**95,161**	74,362
Information technology equipment and software	**544**	222
Communications equipment	**424**	418
Storage facilities	**1,463**	—
Other	**824**	116
Total other plant in service	**3,255**	756
Total plant in service	**$ 98,416**	$ 75,118

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific state PSC orders. Alabama Power and Georgia Power defer and amortize nuclear refueling costs over the unit's operating cycle. The refueling cycles for Alabama Power's Plant Farley and Georgia Power's Plants Hatch and Vogtle Units 1 and 2 range from 18 to 24 months , depending on the unit.

Assets acquired under a capital lease are included in property, plant, and equipment and are further detailed in the table below:

	Asset Balances at December 31,	
	2016	2015
	(in millions)	
Office building	**$ 61**	$ 61
Nitrogen plant	**83**	83
Computer-related equipment	**63**	61
Gas pipeline	**6**	6
Less: Accumulated amortization	**(69)**	(59)
Balance, net of amortization	**$ 144**	$ 152

The amount of non-cash property additions recognized for the years ended December 31, 2016 , 2015 , and 2014 was $1.5 billion , $844 million , and $528 million , respectively. These amounts are comprised of construction-related accounts payable outstanding at each year end. Also, the amount of non-cash property additions associated with capitalized leases for the years ended December 31, 2016 , 2015 , and 2014 was $18 million , $13 million , and $25 million , respectively.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.0% in 2016 and 2015 and 3.1% in 2014 . Depreciation studies are conducted periodically to update the composite rates. These studies are filed with the respective state PSC or other applicable state and federal regulatory agencies for the traditional electric operating companies and natural gas distribution utilities. Accumulated depreciation for utility plant in service totaled $29.3 billion and $23.7 billion at December 31, 2016 and 2015 , respectively. When property subject to composite

depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Certain of Southern Power's generation assets are depreciated on a units-of-production basis, using hours or starts, to better match outage and maintenance costs to the usage of and revenues from these assets. Cost, net of salvage value, of these assets is depreciated on an hours or starts units-of-production basis.

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

See Note 3 under " Regulatory Matters – Gulf Power – Retail Base Rate Cases " for information regarding depreciation and amortization adjustments related to the other cost of removal regulatory liability.

Depreciation of the original cost of other plant in service is provided primarily on a straight-line basis over estimated useful lives ranging from three to 65 years . Accumulated depreciation for other plant in service totaled $550 million and $510 million at December 31, 2016 and 2015 , respectively.

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. Each traditional electric operating company and natural gas distribution utility has received accounting guidance from its state PSC or applicable state regulatory agency allowing the continued accrual or recovery of other retirement costs for long-lived assets that it does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability and amounts to be recovered are reflected in the balance sheet as a regulatory asset.

The liability for AROs primarily relates to facilities that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in April 2015 (CCR Rule), principally ash ponds, and the decommissioning of the Southern Company system's nuclear facilities – Alabama Power's Plant Farley and Georgia Power's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2. In addition, the Southern Company system has retirement obligations related to various landfill sites, asbestos removal, mine reclamation, land restoration related to solar and wind facilities, and disposal of polychlorinated biphenyls in certain transformers. The Southern Company system also has identified retirement obligations related to certain electric transmission and distribution facilities, certain wireless communication towers, property associated with the Southern Company system's rail lines and natural gas pipelines, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded as the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the various state PSCs, and are reflected in the balance sheets. See " Nuclear Decommissioning " herein for additional information on amounts included in rates.

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

	2016	2015
	(in millions)	
Balance at beginning of year	**$ 3,759**	$ 2,201
Liabilities incurred	**66**	662
Liabilities settled	**(171)**	(37)
Accretion	**162**	115
Cash flow revisions	**698**	818
Balance at end of year	**$ 4,514**	$ 3,759

The increases in cash flow revisions and liabilities incurred in 2016 primarily relate to changes in ash pond closure strategy. The cash flow revisions in 2015 are primarily related to an increase in AROs associated with facilities impacted by the CCR Rule and Georgia Power's updated nuclear decommissioning study.

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

Nuclear Decommissioning

The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the IRS. While Alabama Power and Georgia Power are allowed to prescribe an overall investment policy to the Funds' managers, neither Southern Company nor its subsidiaries or affiliates are allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of Southern Company, Alabama Power, and Georgia Power. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

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

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

At December 31, 2016 , investment securities in the Funds totaled $1.6 billion , consisting of equity securities of $878 million , debt securities of $685 million , and $41 million of other securities. At December 31, 2015 , investment securities in the Funds totaled $1.5 billion , consisting of equity securities of $817 million , debt securities of $654 million , and $38 million of other securities. These amounts include the investment securities pledged to creditors and collateral received and exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $1.2 billion , $1.4 billion , and $0.9 billion in 2016 , 2015 , and 2014 , respectively, all of which were reinvested. For 2016 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $114 million , which included $48 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 $11 million , which included $83 million related to unrealized losses on securities held in the Funds at December 31, 2015 . For 2014 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $98 million , which included $19 million related to unrealized gains and losses on securities held in the Funds at December 31, 2014 . While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of the securities and purpose for which the securities were acquired.

For Alabama Power, approximately $19 million and $20 million at December 31, 2016 and 2015, respectively, previously recorded in internal reserves is 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. Alabama Power and Georgia Power have filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

At December 31, 2016 and 2015 , the accumulated provisions for the external decommissioning trust funds were as follows:

	External Trust Funds	
	2016	2015
	(in millions)	
Plant Farley	**$ 790**	$ 734
Plant Hatch	**511**	487
Plant Vogtle Units 1 and 2	**303**	288

Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning as of December 31, 2016 based on the most current studies, which were performed in 2013 for Alabama Power's Plant Farley and in 2015 for the Georgia Power plants, were as follows for Alabama Power's Plant Farley and Georgia Power's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2:

	Plant Farley	Plant Hatch	Plant Vogtle Units 1 and 2
Decommissioning periods:			
Beginning year	2037	2034	2047
Completion year	2076	2075	2079
		(in millions)	
Site study costs:			
Radiated structures	$ 1,362	$ 678	$ 568
Spent fuel management	—	160	147
Non-radiated structures	80	64	89
Total site study costs	$ 1,442	$ 902	$ 804

For ratemaking purposes, Alabama Power's decommissioning costs are based on the site study, and Georgia Power's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities and the site study estimate for spent fuel management as of 2012. Under the 2013 ARP, the Georgia PSC approved Georgia Power's annual decommissioning cost for ratemaking of $4 million and $2 million for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. Georgia Power expects the Georgia PSC to review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs in Georgia Power's 2019 base rate case. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5% and 2.4% for Alabama Power and Georgia Power, respectively, and a trust earnings rate of 7.0% and 4.4% for Alabama Power and Georgia Power, respectively.

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

Allowance for Funds Used During Construction and Interest Capitalized

The traditional electric operating companies and certain of the natural gas distribution utilities record AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable

income. Interest related to the construction of new facilities not included in the traditional electric operating companies' and natural gas distribution utilities' regulated rates is capitalized in accordance with standard interest capitalization requirements. AFUDC and interest capitalized, net of income taxes were 11.4% , 12.8% , and 16.0% of net income for 2016 , 2015 , and 2014 , respectively.

Cash payments for interest totaled $1.1 billion , $809 million , and $732 million in 2016 , 2015 , and 2014 , respectively, net of amounts capitalized of $125 million , $124 million , and $111 million , respectively.

Impairment of Long-Lived Assets

Southern Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change. See Note 3 under " Integrated Coal Gasification Combined Cycle – Kemper IGCC Schedule and Cost Estimate " for additional information.

Goodwill and Other Intangible Assets and Liabilities

At December 31, 2016 and 2015 , goodwill was $6.3 billion and $2 million , respectively. The increase in goodwill relates to Southern Company's acquisitions of PowerSecure and Southern Company Gas. See Note 12 under " Southern Company – Acquisition of PowerSecure " and " – Merger with Southern Company Gas " for additional information.

Goodwill is not amortized, but is subject to an annual impairment test during the fourth quarter of each year, or more frequently if impairment indicators arise. Southern Company evaluated its goodwill in the fourth quarter 2016 and determined that no impairment was required.

At December 31, 2016 , other intangible assets were as follows:

	Estimated Useful Life	Gross Carrying Amount	Accumulated Amortization	Other Intangible Assets, Net
			(in millions)	
Other intangible assets subject to amortization:				
Customer relationships	11-26 years	$ 268	$ (32)	$ 236
Trade names	5-28 years	158	(5)	153
Patents	3-10 years	4	—	4
Backlog	5 years	5	(1)	4
Storage and transportation contracts	1-5 years	64	(2)	62
Software and other	1-12 years	2	—	2
PPA fair value adjustments	19-20 years	456	(22)	434
Total other intangible assets subject to amortization		$ 957	$ (62)	$ 895
Other intangible assets not subject to amortization:				
Federal Communications Commission licenses		75	—	75
Total other intangible assets		$ 1,032	$ (62)	$ 970

At December 31, 2015 , other intangible assets consisted of Southern Power's PPA fair value adjustments with a net carrying amount of $317 million . The increase in other intangible assets primarily relates to Southern Company's acquisitions of PowerSecure and Southern Company Gas, as well as additional PPA fair value adjustments resulting from Southern Power's acquisitions.

Amortization associated with other intangible assets in 2016, 2015, and 2014 was $50 million , $3 million , and $3 million , respectively.

As of December 31, 2016 , the estimated amortization associated with other intangible assets is as follows:

	Amortization
	(in millions)
2017	$ 108
2018	93
2019	74
2020	63
2021	56

Included in other deferred credits and liabilities on the balance sheet is $91 million of intangible liabilities that were recorded during acquisition accounting for transportation contracts at Southern Company Gas. At December 31, 2016 , the accumulated amortization of these intangible liabilities was $21 million . The estimated amortization associated with the intangible liabilities that will be recorded in natural gas revenues is as follows:

	Amortization
	(in millions)
2017	$ 29
2018	24
2019	17

See Note 12 under " Southern Company – Acquisition of PowerSecure " and " – Merger with Southern Company Gas " for additional information. Also see Note 12 under " Southern Power " for additional information regarding Southern Power's PPA fair value adjustments.

Storm Damage Reserves

Each traditional electric operating company maintains a reserve to cover or is allowed to defer and recover the cost of damages from major storms to its transmission and distribution lines and generally the cost of uninsured damages to its generation facilities and other property. In accordance with their respective state PSC orders, the traditional electric operating companies accrued $40 million in each of 2016 , 2015 , and 2014 . Alabama Power, Gulf Power, and Mississippi Power also have authority based on orders from their state PSCs to accrue certain additional amounts as circumstances warrant. In 2016 , 2015 , and 2014 , there were no such additional accruals. See Note 3 under " Regulatory Matters – Alabama Power – Rate NDR " and " Regulatory Matters – Georgia Power – Storm Damage Recovery " for additional information regarding Alabama Power's NDR and Georgia Power's deferred storm costs, respectively.

Leveraged Leases

Southern Company has several leveraged lease agreements, with original terms ranging up to 45 years , which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. Southern Company reviews all important lease assumptions at least annually, or more frequently if events or changes in circumstances indicate that a change in assumptions has occurred or may occur. These assumptions include the effective tax rate, the residual value, the credit quality of the lessees, and the timing of expected tax cash flows.

Southern Company's net investment in domestic and international leveraged leases consists of the following at December 31:

	2016	2015
	(in millions)	
Net rentals receivable	**$ 1,481**	$ 1,487
Unearned income	**(707)**	(732)
Investment in leveraged leases	**774**	755
Deferred taxes from leveraged leases	**(309)**	(303)
Net investment in leveraged leases	**$ 465**	$ 452

A summary of the components of income from the leveraged leases follows:

	2016	2015	2014
		(in millions)	
Pretax leveraged lease income	**$ 25**	$ 20	$ 24
Income tax expense	**(9)**	(7)	(9)
Net leveraged lease income	**$ 16**	$ 13	$ 15

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 of the electric utilities. Fuel is recorded to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the traditional electric operating companies through fuel cost recovery rates approved by each state PSC. Emissions allowances granted by the EPA are included in inventory at zero cost.

Natural Gas for Sale

The natural gas distribution utilities, with the exception of Nicor Gas, carry natural gas inventory on a weighted average cost of gas (WACOG) basis.

Nicor Gas' natural gas inventory is carried at cost on a last-in, first-out (LIFO) basis. Inventory decrements occurring during the year that are restored prior to year-end are charged to cost of natural gas at the estimated annual replacement cost. Inventory decrements that are not restored prior to year-end are charged to cost of natural gas at the actual LIFO cost of the inventory layers liquidated. The cost of natural gas, including inventory costs, is recovered from customers under a purchased gas recovery mechanism adjusted for differences between actual costs and amounts billed; therefore, LIFO liquidations have no impact on Southern Company's net income.

Natural gas inventories for Southern Company Gas' non-utility businesses are carried at the lower of weighted average cost or current market price, with cost determined on a WACOG basis. For any declines in market prices below the WACOG considered to be other than temporary, an adjustment is recorded to reduce the value of natural gas inventories to market value.

Financial Instruments

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

Beginning in 2016, the Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. At December 31, 2016 , the amount included in accounts payable in the

balance sheets that the Company has recognized for the obligation to return cash collateral arising from derivative instruments was immaterial.

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

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges and marketable securities, certain changes in pension and other postretirement benefit plans, reclassifications for amounts included in net income, and dividends on preferred and preference stock of subsidiaries.

Accumulated OCI (loss) balances, net of tax effects, were as follows:

	Qualifying Hedges	Marketable Securities	Pension and Other Postretirement Benefit Plans	Accumulated Other Comprehensive Income (Loss)
		(in millions)		
Balance at December 31, 2015	$ (48)	$ —	$ (82)	$ (130)
Current period change	(67)	—	17	(50)
Balance at December 31, 2016	**$ (115)**	**$ —**	**$ (65)**	**$ (180)**

2. RETIREMENT BENEFITS

Southern Company has a defined benefit, trusteed, pension plan covering substantially all employees, with the exception of employees at Southern Company Gas, as discussed below, and PowerSecure. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). On December 19, 2016, the traditional electric operating companies and certain other subsidiaries voluntarily contributed an aggregate of $900 million to Southern Company's qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2017 . Southern Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, Southern Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The traditional electric operating companies fund related other postretirement trusts to the extent required by their respective regulatory commissions. For the year ending December 31, 2017 , no other postretirement trust contributions are expected.

In addition, Southern Company Gas has a qualified defined benefit, trusteed, pension plan covering certain eligible employees, which was closed in 2012 to new employees. This qualified pension plan is funded in accordance with requirements of ERISA. Southern Company Gas voluntarily contributed $125 million to its qualified pension plan on September 12, 2016. No mandatory contributions to the Southern Company Gas qualified pension plan are anticipated for the year ending December 31, 2017. Southern Company Gas also provides certain non-qualified defined benefit and defined contribution pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, Southern Company Gas provides certain medical care and life insurance benefits for eligible retired employees through a postretirement benefit plan. Southern Company Gas also has a separate unfunded supplemental retirement health care plan that provides medical care and life insurance benefits to employees of discontinued businesses. For the year ending December 31, 2017 , no other postretirement trust contributions are expected.

Actuarial Assumptions

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

Assumptions used to determine net periodic costs:	2016	2015	2014
Pension plans			
Discount rate – benefit obligations	**4.58%**	4.17%	5.02%
Discount rate – interest costs	**3.88**	4.17	5.02
Discount rate – service costs	**4.98**	4.48	5.02
Expected long-term return on plan assets	**8.16**	8.20	8.20
Annual salary increase	**4.37**	3.59	3.59
Other postretirement benefit plans			
Discount rate – benefit obligations	**4.38%**	4.04%	4.85%
Discount rate – interest costs	**3.66**	4.04	4.85
Discount rate – service costs	**4.85**	4.39	4.85
Expected long-term return on plan assets	**6.66**	6.97	7.15
Annual salary increase	**4.37**	3.59	3.59

Assumptions used to determine benefit obligations:	2016	2015
Pension plans		
Discount rate	**4.40%**	4.67%
Annual salary increase	**4.37**	4.46
Other postretirement benefit plans		
Discount rate	**4.23%**	4.51%
Annual salary increase	**4.37**	4.46

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

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

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

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

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 128	$ 110
Service and interest costs	4	3

Pension Plans

The total accumulated benefit obligation for the pension plans was $11.3 billion at December 31, 2016 and $9.6 billion at December 31, 2015 . Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2016 and 2015 were as follows:

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 10,542**	$ 10,909
Acquisitions	**1,244**	—
Service cost	**262**	257
Interest cost	**422**	445
Benefits paid	**(466)**	(487)
Actuarial (gain) loss	**381**	(582)
Balance at end of year	**12,385**	10,542
Change in plan assets		
Fair value of plan assets at beginning of year	**9,234**	9,690
Acquisitions	**837**	—
Actual return (loss) on plan assets	**902**	(14)
Employer contributions	**1,076**	45
Benefits paid	**(466)**	(487)
Fair value of plan assets at end of year	**11,583**	9,234
Accrued liability	**$ (802)**	$ (1,308)

At December 31, 2016 , the projected benefit obligations for the qualified and non-qualified pension plans were $11.8 billion and $627 million , respectively. All pension plan assets are related to the qualified pension plans.

Amounts presented in the following tables do not include regulatory assets of $369 million recognized by Southern Company Gas associated with its pension plans prior to its acquisition on July 1, 2016.

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

	2016	2015
	(in millions)	
Other regulatory assets, deferred	**$ 3,207**	$ 2,998
Other current liabilities	**(53)**	(46)
Employee benefit obligations	**(749)**	(1,262)
Other regulatory liabilities, deferred	**(87)**	—
Accumulated OCI	**100**	125

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

	Prior Service Cost	Net (Gain) Loss
	(in millions)	
Balance at December 31, 2016:		
Accumulated OCI	**$ 4**	**$ 96**
Regulatory assets	**51**	**3,069**
Total	**$ 55**	**$ 3,165**
Balance at December 31, 2015:		
Accumulated OCI	$ 3	$ 122
Regulatory assets	27	2,971
Total	$ 30	$ 3,093
Estimated amortization in net periodic pension cost in 2017:		
Accumulated OCI	**$ 1**	**$ 7**
Regulatory assets	**11**	**155**
Total	**$ 12**	**$ 162**

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

	Accumulated OCI	Regulatory Assets
	(in millions)	
Balance at December 31, 2014	$ 134	$ 3,073
Net (gain) loss	1	155
Reclassification adjustments:		
Amortization of prior service costs	(1)	(24)
Amortization of net gain (loss)	(9)	(206)
Total reclassification adjustments	(10)	(230)
Total change	(9)	(75)
Balance at December 31, 2015	$ 125	$ 2,998
Net (gain) loss	**(20)**	**243**
Change in prior service costs	**2**	**37**
Reclassification adjustments:		
Amortization of prior service costs	**(1)**	**(13)**
Amortization of net gain (loss)	**(6)**	**(145)**
Total reclassification adjustments	**(7)**	**(158)**
Total change	**(25)**	**122**
Balance at December 31, 2016	**$ 100**	**$ 3,120**

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

Components of net periodic pension cost were as follows:

	2016	2015	2014
		(in millions)	
Service cost	**$ 262**	$ 257	$ 213
Interest cost	**422**	445	435
Expected return on plan assets	**(782)**	(724)	(645)
Recognized net (gain) loss	**150**	215	110
Net amortization	**14**	25	26
Net periodic pension cost	**$ 66**	$ 218	$ 139

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

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

	Benefit Payments
	(in millions)
2017	$ 571
2018	593
2019	620
2020	646
2021	666
2022 to 2026	3,673

Other Postretirement Benefits

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

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 1,989**	$ 1,986
Acquisitions	**338**	—
Service cost	**22**	23
Interest cost	**76**	78
Benefits paid	**(119)**	(102)
Actuarial (gain) loss	**(16)**	(38)
Plan amendments	—	34
Retiree drug subsidy	**7**	8
Balance at end of year	**2,297**	1,989
Change in plan assets		
Fair value of plan assets at beginning of year	**833**	900
Acquisitions	**100**	—
Actual return (loss) on plan assets	**58**	(12)
Employer contributions	**65**	39
Benefits paid	**(112)**	(94)
Fair value of plan assets at end of year	**944**	833
Accrued liability	**$ (1,353)**	$ (1,156)

Amounts presented in the following tables do not include regulatory assets of $77 million recognized by Southern Company Gas associated with its other postretirement benefit plan prior to its acquisition on July 1, 2016.

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

	2016	2015
	(in millions)	
Other regulatory assets, deferred	**$ 419**	$ 433
Other current liabilities	**(4)**	(4)
Employee benefit obligations	**(1,349)**	(1,152)
Other regulatory liabilities, deferred	**(41)**	(22)
Accumulated OCI	**7**	8

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

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

	Prior Service Cost	Net (Gain) Loss
	(in millions)	
Balance at December 31, 2016:		
Accumulated OCI	**$ —**	**$ 7**
Net regulatory assets	**25**	**353**
Total	**$ 25**	**$ 360**
Balance at December 31, 2015:		
Accumulated OCI	$ —	$ 8
Net regulatory assets	32	379
Total	$ 32	$ 387
Estimated amortization as net periodic postretirement benefit cost in 2017:		
Net regulatory assets	**$ 6**	**$ 13**

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

	Accumulated OCI	Net Regulatory Assets (Liabilities)
	(in millions)	
Balance at December 31, 2014	$ 8	$ 366
Net (gain) loss	—	33
Change in prior service costs	—	33
Reclassification adjustments:		
Amortization of prior service costs	—	(4)
Amortization of net gain (loss)	—	(17)
Total reclassification adjustments	—	(21)
Total change	—	45
Balance at December 31, 2015	$ 8	$ 411
Net (gain) loss	**(1)**	**(13)**
Reclassification adjustments:		
Amortization of prior service costs	**—**	**(6)**
Amortization of net gain (loss)	**—**	**(14)**
Total reclassification adjustments	**—**	**(20)**
Total change	**(1)**	**(33)**
Balance at December 31, 2016	**$ 7**	**$ 378**

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

	2016	2015	2014
		(in millions)	
Service cost	$ 22	$ 23	$ 21
Interest cost	76	78	79
Expected return on plan assets	(60)	(58)	(59)
Net amortization	21	21	6
Net periodic postretirement benefit cost	$ 59	$ 64	$ 47

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

	Benefit Payments	Subsidy Receipts	Total
		(in millions)	
2017	$ 145	$ (10)	$ 135
2018	150	(11)	139
2019	155	(12)	143
2020	159	(13)	146
2021	162	(14)	148
2022 to 2026	823	(73)	750

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policies for both the pension plans and the other postretirement benefit plans cover a diversified mix of assets as described below. Derivative instruments may be used to gain efficient exposure to the various asset classes and as hedging tools. Additionally, the Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The investment strategy for plan assets related to the Company's qualified pension plans 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 plans 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 Southern Company plan employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies and Benefit Plan Asset Fair Values

A description of the major asset classes that the pension and other postretirement benefit plans are comprised of, along with the valuation methods used for fair value measurement, is provided below:

Description	Valuation Methodology
● **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.	Domestic and International equities such as common stocks, American depositary receipts, and real estate investment trusts that trade on public exchanges are classified as Level 1 investments and are valued at the closing price in the active market. Equity funds with unpublished prices are valued as Level 2 when the underlying holdings are comprised of Level 1 or Level 2 equity securities.
● **Fixed income:** A mix of domestic and international bonds.	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.
● **Trust-owned life insurance (TOLI):** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.	Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate accounts. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
● **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 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.	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.

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

The fair values, and actual allocations relative to the target allocations, of Southern Company's pension plan (excluding Southern Company Gas) as of December 31, 2016 and 2015 are presented below. 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.

These fair values exclude cash, receivables related to investment income and pending investment sales, and payables related to pending investment purchases.

	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	Target Allocation	Actual Allocation
			(in millions)				
Assets:							
Domestic equity [*]	$ 2,010	$ 927	$ —	$ —	$ 2,937	26%	29%
International equity [*]	1,231	1,110	—	—	2,341	25	22
Fixed income:						23	29
U.S. Treasury, government, and agency bonds	—	588	—	—	588		
Mortgage- and asset-backed securities	—	13	—	—	13		
Corporate bonds	—	991	—	—	991		
Pooled funds	—	524	—	—	524		
Cash equivalents and other	996	2	—	—	998		
Real estate investments	310	—	—	1,152	1,462	14	13
Special situations	—	—		180	180	3	2
Private equity	—	—	—	549	549	9	5
Total	$ 4,547	$ 4,155	$ —	$ 1,881	$ 10,583	100%	100%

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

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

As of December 31, 2015:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total	Target Allocation	Actual Allocation
	(in millions)						
Assets:							
Domestic equity [(a)]	$ 1,632	$ 681	$ —	$ —	$ 2,313	26%	30%
International equity [(a)]	1,190	962	—	—	2,152	25	23
Fixed income:						23	23
U.S. Treasury, government, and agency bonds	—	454	—	—	454		
Mortgage- and asset-backed securities	—	199	—	—	199		
Corporate bonds	—	1,140	—	—	1,140		
Pooled funds	—	500	—	—	500		
Cash equivalents and other	—	145	—	—	145		
Real estate investments	299	—	—	1,185	1,484	14	16
Special situations [(b)]	—	—	—	160	160	3	2
Private equity	—	—	—	536	536	9	6
Total	$ 3,121	$ 4,081	$ —	$ 1,881	$ 9,083	100%	100%
Liabilities:							
Derivatives	$ (1)	$ —	$ —	$ —	$ (1)		
Total	$ 3,120	$ 4,081	$ —	$ 1,881	$ 9,082	100%	100%

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

(b) The 2015 presentation above has been revised to separately reflect special situations, consistent with the 2016 presentation.

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

The fair values of Southern Company Gas' pension plan assets for the period ended December 31, 2016 are presented below. The fair value measurements exclude cash, receivables related to investment income, pending investment sales, and payables related to pending investment purchases. For 2016, special situations (absolute return and hedge funds) investment assets are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using				
As of December 31, 2016:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Assets:					
Domestic equity [*]	$ 142	$ 343	$ —	$ —	$ 485
International equity [*]	—	185	—	—	185
Fixed income:					
U.S. Treasury, government, and agency bonds	—	85	—	—	85
Corporate bonds	—	41	—	—	41
Pooled funds	—	66	—	—	66
Cash equivalents and other	12	5	—	83	100
Real estate investments	4	—	—	15	19
Private equity	—	—	—	2	2
Total	$ 158	$ 725	$ —	$ 100	$ 983

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

The assets of Southern Company Gas' pension plan were allocated 69% equity, 20% fixed income, 1% cash, and 10% other at December 31, 2016 , compared to the asset class targets of 53% equity, 15% fixed income, 2% cash, and 30% other. Southern Company Gas' pension plan investment policy provides for variation around the target asset allocation in the form of ranges.

The fair values of Southern Company's (excluding Southern Company Gas) other postretirement benefit plan assets as of December 31, 2016 and 2015 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investment sales, and payables related to pending investment purchases.

	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**	**Target Allocation**	**Actual Allocation**
	(in millions)						
Assets:							
Domestic equity [(*)]	$ 118	$ 28	$ —	$ —	$ 146	39%	40%
International equity [(*)]	37	61	—	—	98	23	21
Fixed income:						29	31
U.S. Treasury, government, and agency bonds	—	24	—	—	24		
Corporate bonds	—	30	—	—	30		
Pooled funds	—	49	—	—	49		
Cash equivalents and other	41	—	—	—	41		
Trust-owned life insurance	—	382	—	—	382		
Real estate investments	11	—	—	35	46	5	5
Special situations	—	—	—	5	5	1	1
Private equity	—	—	—	17	17	3	2
Total	$ 207	$ 574	$ —	$ 57	$ 838	100%	100%

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

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

As of December 31, 2015:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total	Target Allocation	Actual Allocation
	(in millions)						
Assets:							
Domestic equity [(a)]	$ 106	$ 52	$ —	$ —	$ 158	42%	38%
International equity [(a)]	40	63	—	—	103	21	23
Fixed income:						28	30
U.S. Treasury, government, and agency bonds	—	22	—	—	22		
Mortgage- and asset-backed securities	—	7	—	—	7		
Corporate bonds	—	38	—	—	38		
Pooled funds	—	42	—	—	42		
Cash equivalents and other	11	9	—	—	20		
Trust-owned life insurance	—	370	—	—	370		
Real estate investments	11	—	—	40	51	5	6
Special situations [(b)]	—	—	—	5	5	1	1
Private equity	—	—	—	18	18	3	2
Total	$ 168	$ 603	$ —	$ 63	$ 834	100%	100%

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

(b) The 2015 presentation above has been revised to separately reflect special situations, consistent with the 2016 presentation.

The fair values of Southern Company Gas' other postretirement benefit plan assets for the period ended December 31, 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investment sales, and payables related to pending investment purchases. For 2016, special situations (absolute return and hedge funds) investment assets are presented in the tables below based on the nature of the investment.

As of December 31, 2016:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
	(in millions)				
Assets:					
Domestic equity [(*)]	$ 3	$ 58	$ —	$ —	$ 61
International equity [(*)]	—	18	—	—	18
Fixed income:					
Pooled funds	—	23	—	—	23
Cash equivalents and other	1	—	—	2	3
Total	$ 4	$ 99	$ —	$ 2	$ 105

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

The assets of Southern Company Gas' other postretirement benefit plans were allocated 74% equity, 23% fixed income, 1% cash, and 2% other at December 31, 2016 , compared to the asset class targets of 72% equity, 24% fixed income, 1% cash, and 3%

other. Southern Company Gas' other postretirement plan's investment policy provides for some variation in these targets in the form of ranges around the target.

Employee Savings Plan

Southern Company and its subsidiaries also sponsor 401(k) defined contribution plans covering substantially all employees and provide matching contributions up to specified percentages of an employee's eligible pay. Total matching contributions made to the plans for 2016 , 2015 , and 2014 were $105 million , $92 million , and $87 million , respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

Nicor Gas and Nicor Energy Services Company, wholly-owned subsidiaries of Southern Company Gas, and Nicor Inc. are defendants in a putative class action initially filed in 2011 in state court in Cook County, Illinois. The plaintiffs purport to represent a class of the customers who purchased the Gas Line Comfort Guard product from Nicor Energy Services Company and variously allege that the marketing, sale, and billing of the Gas Line Comfort Guard product violated the Illinois Consumer Fraud and Deceptive Business Practices Act, constituting common law fraud and resulting in unjust enrichment of these entities. The plaintiffs seek, on behalf of the classes they purport to represent, actual and punitive damages, interest, costs, attorney fees, and injunctive relief. On February 8, 2017, the judge denied the plaintiffs' motion for class certification and Southern Company Gas' motion for summary judgment. The ultimate outcome of this matter cannot be determined at this time.

On January 20, 2017, a purported securities class action complaint was filed against Southern Company and certain of its and Mississippi Power's officers in the U.S. District Court for the Northern District of Georgia, Atlanta Division, by Monroe County Employees' Retirement System on behalf of all persons who purchased shares of Southern Company's common stock between April 25, 2012 and October 29, 2013. The complaint alleges that Southern Company and certain of its and Mississippi Power's officers made materially false and misleading statements regarding the Kemper IGCC in violation of certain provisions under the Securities Exchange Act of 1934, as amended. The complaint seeks, among other things, compensatory damages and litigation costs and attorneys' fees. Southern Company believes this legal challenge has no merit; however, an adverse outcome in this proceeding could have an impact on Southern Company's results of operations, financial condition, and liquidity. Southern Company will vigorously defend itself in this matter, and the ultimate outcome of this matter cannot be determined at this time.

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

Environmental Matters

Environmental Remediation

The Southern Company system must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Southern Company system could incur substantial costs to clean up affected sites. The traditional electric operating companies and the natural gas distribution utilities in Illinois, New Jersey, Georgia, and Florida, have each received authority from their respective state PSCs or other applicable state regulatory agencies to recover approved environmental compliance costs through regulatory mechanisms. These regulatory mechanisms are adjusted annually or as necessary within limits approved by the state PSCs or other applicable state regulatory agencies.

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

Gulf Power's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $44 million as of December 31, 2016 . These estimated costs primarily relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at Gulf Power's substations. The schedule for completion of the remediation projects is subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through Gulf Power's environmental cost recovery clause; therefore, these liabilities have no impact on net income.

Southern Company Gas' environmental remediation liability as of December 31, 2016 was $426 million based on the estimated cost of environmental investigation and remediation associated with known current and former operating sites. These environmental remediation expenditures are recoverable from customers through rate mechanisms approved by the applicable state regulatory agencies of the natural gas distribution utilities, with the exception of one site representing $5 million of the total accrued remediation costs.

In September 2015, the EPA filed an administrative complaint and notice of opportunity for hearing against Nicor Gas. The complaint alleges violation of the regulatory requirements applicable to polychlorinated biphenyls in the Nicor Gas natural gas distribution system and the EPA seeks a total civil penalty of approximately $0.3 million . On January 26, 2017, the EPA notified Nicor Gas that it agreed to voluntarily dismiss its administrative complaint with prejudice and without payment of a civil penalty or other further obligation on the part of Nicor Gas.

The ultimate outcome of these matters cannot be determined at this time; however, the final disposition of these matters is not expected to have a material impact on Southern Company's financial statements.

Nuclear Fuel Disposal Costs

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

In 2014, the Court of Federal Claims entered a judgment in favor of Georgia Power and Alabama Power in their spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. In March 2015, Georgia Power recovered approximately $18 million , based on its ownership interests, which was credited to accounts where the original costs were charged and reduced rate base, fuel, and cost of service for the benefit of customers. Also in March 2015, Alabama Power recovered approximately $26 million , which was applied to reduce the cost of service for the benefit of customers.

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

On-site dry spent fuel storage facilities are operational at all three plants and can be expanded to accommodate spent fuel through the expected life of each plant.

FERC Matters

Market-Based Rate Authority

The traditional electric operating companies and Southern Power have authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric operating companies' 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 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 and Southern Power filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.

On December 9, 2016, the traditional electric operating companies 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' and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The traditional electric operating companies and Southern Power expect to make a compliance filing within 30 days accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

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

Southern Company Gas

At December 31, 2016, Southern Company Gas' gas midstream operations was involved in three gas pipeline construction projects with expected capital expenditures of approximately $780 million . These projects, along with Southern Company Gas' existing pipelines, are intended to provide diverse sources of natural gas supplies to customers, resolve current and long-term supply planning for new capacity, enhance system reliability, and generate economic development in the areas served. One of these projects received FERC approval in August 2016. The remaining projects are pending FERC approval, which is expected to occur in 2017. The ultimate outcome of this matter cannot be determined at this time.

Regulatory Matters

Alabama Power

Rate RSE

The Alabama PSC has adopted Rate RSE that provides for periodic annual adjustments based upon Alabama Power's projected weighted cost of equity (WCE) compared to an allowable range. Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Retail rates remain unchanged when the WCE ranges between 5.75% and 6.21% 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 Alabama Power (i) has an "A" credit rating equivalent with at least one of the recognized rating agencies or (ii) is in the top one-third of a designated customer value benchmark survey. Rate RSE adjustments for any two -year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0% . If Alabama Power's actual retail return is above the allowed WCE range, 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.

On December 1, 2016, Alabama Power made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2017. The Rate RSE adjustment was an increase of 4.48% , or $245 million annually, effective January 1, 2017 and includes the performance based adder of 0.07% . Under the terms of Rate RSE, the maximum increase for 2018 cannot exceed 3.52% .

As of December 31, 2016, the 2016 retail return exceeded the allowed WCE range; therefore, Alabama Power established a $73 million Rate RSE refund liability. In accordance with an order issued on February 14, 2017 by the Alabama PSC, Alabama Power was directed to apply the full amount of the refund to reduce the under recovered balance of Rate CNP PPA.

Rate CNP PPA

Alabama Power's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under Rate CNP. Alabama Power may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 8, 2016, the Alabama PSC issued a consent order that Alabama Power leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2016 through March 31, 2017. No adjustment to Rate CNP PPA is expected in 2017. As of December 31, 2016 and 2015, Alabama Power had an under recovered certificated PPA balance of $142 million and $99 million , respectively, which is included in other regulatory assets, deferred in the balance sheet.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, Alabama Power was authorized to eliminate the under recovered balance in Rate CNP PPA at December 31, 2016 , which totaled approximately $142 million . As discussed herein under "Rate RSE," Alabama Power will utilize the full amount of its $73 million Rate RSE refund liability to reduce the amount of the Rate CNP PPA under recovery and will reclassify 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 Alabama

Power's next depreciation study, which is expected to occur within the next three to five years . Alabama Power's current depreciation study became effective January 1, 2017.

Rate CNP Compliance

Rate CNP Compliance allows for the recovery of Alabama Power'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 Alabama Power'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 revenues or net income, but will affect annual cash flow. Changes in compliance related operations and maintenance expenses and depreciation generally will have no effect on net income.

On December 6, 2016, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2017 the factors associated with Alabama Power's compliance costs for the year 2016. As stated in the consent order, any under-collected amount for prior years will be deemed recovered before the recovery of any current year amounts. Any under recovered amounts associated with 2017 will be reflected in the 2018 filing.

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

Rate ECR

Alabama Power has established energy cost recovery rates under Alabama Power's Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. Alabama Power, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on Southern Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH. In December 2015, the Alabama PSC issued a consent order that Alabama Power decrease the Rate ECR factor from 2.681 cents per KWH to 2.030 cents per KWH.

On December 6, 2016, the Alabama PSC approved a decrease in Alabama Power's Rate ECR factor from 2.030 to 2.015 cents per KWH, equal to 0.15% , or $8 million annually, based upon projected billings, effective January 1, 2017. The rate will return to 5.910 cents per KWH in 2018 absent a further order from the Alabama PSC.

At December 31, 2016 and 2015, Alabama Power's over recovered fuel costs totaled $76 million and $238 million , respectively, and are 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.

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

Rate NDR

Based on an order from the Alabama PSC, Alabama Power maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24 -month period. The Alabama PSC order gives Alabama Power authority to record a deficit balance in the NDR when costs of

storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. Alabama Power has the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant. The order allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million . Alabama Power may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance Alabama Power's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. No such accruals were recorded or designated in any period presented.

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

Environmental Accounting Order

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

In April 2015, as part of its environmental compliance strategy, Alabama Power retired Plant Gorgas Units 6 and 7 (200 MWs). Additionally, in April 2015, Alabama Power ceased using coal at Plant Barry Units 1 and 2 (250 MWs), but such units will remain available on a limited basis with natural gas as the fuel source. In accordance with the joint stipulation entered in connection with a civil enforcement action by the EPA, Alabama Power retired Plant Barry Unit 3 (225 MWs) in August 2015 and it is no longer available for generation. In April 2016, as part of its environmental compliance strategy, Alabama Power ceased using coal at Plant Greene County Units 1 and 2 (300 MWs representing Alabama Power'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, Alabama Power transferred the unrecovered plant asset balances to a regulatory asset at their respective retirement dates. The regulatory asset will be amortized and recovered through Rate CNP Compliance over the units' remaining useful lives, as established prior to the decision for retirement; therefore, these decisions associated with coal operations had no significant impact on Southern Company's financial statements.

Georgia Power

Rate Plans

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

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

Under the 2013 ARP, Georgia Power's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00% . Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. In 2014, Georgia Power's retail ROE exceeded 12.00% , and Georgia Power refunded to retail customers approximately $11 million in 2016, as approved by the Georgia PSC on February 18, 2016. In 2015, Georgia Power's retail ROE was within the allowed retail ROE range. In 2016, Georgia Power's retail ROE exceeded 12.00% , and Georgia Power expects to refund to retail customers

approximately $40 million , subject to review and approval by the Georgia PSC. The ultimate outcome of this matter cannot be determined at this time.

Integrated Resource Plan

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

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

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

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

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

Fuel Cost Recovery

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

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

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

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

Storm Damage Recovery

As of December 31, 2016 , the balance in Georgia Power's regulatory asset related to storm damage was $206 million . During October 2016, Hurricane Matthew caused significant damage to Georgia Power's transmission and distribution facilities. As of December 31, 2016, Georgia Power had recorded incremental restoration cost related to this hurricane of $121 million , of which approximately $116 million was charged to the storm damage reserve and the remainder was capitalized. Georgia Power is accruing $30 million annually through December 31, 2019, as provided in the 2013 ARP, to the storm damage reserve to cover the operations and maintenance costs of damages from major storms to its transmission and distribution facilities, which is recoverable through base rates. The rate of recovery of storm damage costs after December 31, 2019 is expected to be adjusted in

Georgia Power's 2019 base rate case. As a result of this regulatory treatment, costs related to storms are not expected to have a material impact on Southern Company's financial statements.

Nuclear Construction

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

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

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

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

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

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

Georgia Power is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. In accordance with the 2009 certification order, Georgia Power requested amendments to the Plant Vogtle Units 3 and 4 certificate in both the February 2013 (eighth VCM) and February 2015 (twelfth VCM) filings, when projected construction capital costs to be borne by Georgia Power increased by 5% above the certified costs and estimated in-service dates were extended. In October 2013, the Georgia PSC approved a stipulation (2013 Stipulation) between Georgia Power and the Georgia PSC Staff to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate until the completion of

Plant Vogtle Unit 3 or earlier if deemed appropriate by the Georgia PSC and Georgia Power. In April 2015, the Georgia PSC recognized that the certified cost and the 2013 Stipulation did not constitute a cost recovery cap and deemed the amendment requested in the February 2015 filing unnecessary and withdrawn until the completion of construction of Plant Vogtle Unit 3 consistent with the 2013 Stipulation.

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

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

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

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

approximately $3.9 billion as of December 31, 2016, and Georgia Power had incurred $1.3 billion in financing costs through December 31, 2016.

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

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

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

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

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

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

Gulf Power

Retail Base Rate Cases

In 2013, the Florida PSC approved a settlement agreement among Gulf Power and all of the intervenors to Gulf Power's retail base rate case (Gulf Power 2013 Rate Case Settlement Agreement). Under the terms of the Gulf Power 2013 Rate Case Settlement Agreement, Gulf Power (1) increased base rates approximately $35 million and $20 million annually effective January 2014 and 2015, respectively; (2) continued its authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); and (3) accrued a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 through January 1, 2017.

The Gulf Power 2013 Rate Case Settlement Agreement also provides that Gulf Power may reduce depreciation and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million from January 2014 through June 2017. In any given month, such depreciation reduction may not exceed the amount necessary for the retail ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized retail ROE range then in effect. Recovery of the regulatory asset will occur over a period to be determined by the Florida PSC in the Gulf Power 2016 Rate Case, as defined below. For 2014 and 2015, Gulf Power recognized reductions in depreciation expense of $8.4 million and $20.1 million , respectively. No net reduction in depreciation was recorded by Gulf Power in 2016.

On October 12, 2016, Gulf Power filed a petition (Gulf Power 2016 Rate Case) with the Florida PSC requesting an annual increase in retail rates and charges of $106.8 million based on the projected test year of January 1, 2017 through December 31, 2017 and a retail ROE of 11% compared to the current retail ROE of 10.25% . The requested increase includes recovery of the portion of Plant Scherer Unit 3 that has been rededicated to serving retail customers following the contract expirations at the end of 2015 and May 2016. If retail recovery of Plant Scherer Unit 3 is not approved by the Florida PSC in the 2016 Rate Case, Gulf Power may consider an asset sale. The current book value of Gulf Power's ownership of Plant Scherer Unit 3 could exceed market value which could result in a material loss. The Florida PSC is expected to make a decision on the Gulf Power 2016 Rate Case in the second quarter 2017. Gulf Power has requested that the increase in base rates, if approved by the Florida PSC, become effective in July 2017. The ultimate outcome of this matter cannot be determined at this time.

Southern Company Gas

Natural Gas Cost Recovery

Southern Company Gas has established natural gas cost recovery rates that are approved by the applicable state regulatory agencies in the states in which it serves. Natural gas cost recovery revenues are adjusted for differences in actual recoverable natural gas costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect cash flow.

Regulatory Infrastructure Programs

Six of Southern Company Gas' seven natural gas distribution utilities are involved in ongoing capital projects associated with infrastructure improvement programs that have been previously approved by their applicable state regulatory agencies and provide an appropriate return on invested capital. These infrastructure improvement programs are designed to update or expand the natural gas distribution systems of the natural gas distribution utilities to improve reliability and meet operational flexibility and growth. Initial program lengths range from four to 10 years , with the longest set to expire in 2025.

On February 21, 2017, the Georgia PSC approved a rate adjustment mechanism for Atlanta Gas Light that included the 2017 capital investment associated with a four -year extension of one of its existing infrastructure programs, with a total additional investment of $177 million through 2020. In addition, Elizabethtown Gas currently has a proposed infrastructure improvement program pending approval by the New Jersey Board of Public Utilities requesting to invest more than $1.1 billion through 2027.

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

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

The Kemper IGCC utilizes IGCC technology with an expected output capacity of 582 MWs. The Kemper IGCC is fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by Mississippi Power and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation in 2013. In connection with the Kemper IGCC, Mississippi Power constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the transport of captured CO_2 for use in enhanced oil recovery.

Kemper IGCC Schedule and Cost Estimate

In 2012, the Mississippi PSC issued the 2012 MPSC CPCN Order, a detailed order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC. The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC CPCN Order was $2.4 billion , net of $245 million of grants awarded to the Kemper IGCC project by the DOE under the Clean Coal Power Initiative Round 2 (Initial DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and AFUDC related to the Kemper IGCC. The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion , with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. The Kemper IGCC was originally projected to be placed in service in May 2014. Mississippi Power placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service in August 2014. The remainder of the plant, including the gasifiers and the gas clean-up facilities, represents first-of-a-kind technology. The initial production of syngas began on July 14, 2016 for gasifier "B" and on September 13, 2016 for gasifier "A." Mississippi Power achieved integrated operation of both gasifiers on January 29, 2017, including the production of electricity from syngas in both combustion turbines. Mississippi Power subsequently completed a brief outage to repair and make modifications to further improve the plant's ability to achieve sustained operations sufficient to support placing the plant in service for customers. Efforts to reach sustained operation of both gasifiers and production of electricity from syngas in both combustion turbines are in process. The plant has produced and captured CO_2 , and has produced sulfuric acid and ammonia, all of acceptable quality under

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the related off-take agreements. On February 20, 2017, Mississippi Power determined gasifier "B," which has been producing syngas over 60% of the time since early November 2016, requires an outage to remove ash deposits from its ash removal system. Gasifier "A" and combustion turbine "A" are expected to remain in operation, producing electricity from syngas, as well as producing chemical by-products. As a result, Mississippi Power currently expects the remainder of the Kemper IGCC, including both gasifiers, will be placed in service by mid-March 2017.

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

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

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

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

(c) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion , net of the Initial DOE Grants and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions). The Current Cost Estimate and the Actual Costs include non-incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service in August 2014 that are subject to the $2.88 billion cost cap and exclude post-in-service costs for the lignite mine. See " Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order " herein for additional information.

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

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

(f) On April 8, 2016, Mississippi Power received approximately $137 million in additional grants from the DOE for the Kemper IGCC (Additional DOE Grants), which are expected to be used to reduce future rate impacts for customers.

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

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

Mississippi Power does not intend to seek rate recovery for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. Southern Company recorded pre-

tax charges to income for revisions to the cost estimate of $348 million ($215 million after tax), $365 million ($226 million after tax), and $868 million ($536 million after tax) in 2016, 2015, and 2014, respectively. Since 2013, in the aggregate, Southern Company has incurred charges of $2.76 billion ($1.71 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2016. The increases to the cost estimate in 2016 primarily reflect $186 million for the extension of the Kemper IGCC's projected in-service date from August 31, 2016 to March 15, 2017 and $162 million for increased efforts related to operational readiness and challenges in start-up and commissioning activities, including the cost of repairs and modifications to both gasifiers, mechanical improvements to coal feed and ash management systems, and outage work, as well as certain post-in-service costs expected to be subject to the cost cap.

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

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

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

Rate Recovery of Kemper IGCC Costs

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

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

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

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

Prudence

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

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

Economic Viability Analysis

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

As a result of the updated long-term natural gas forecast, as well as the revised operating expense projections reflected in the discovery docket filings discussed above, on February 21, 2017, Mississippi Power filed an updated project economic viability analysis of the Kemper IGCC as required under the 2012 MPSC CPCN Order confirming authorization of the Kemper IGCC. The project economic viability analysis measures the life cycle economics of the Kemper IGCC compared to feasible alternatives, natural gas combined cycle generating units, under a variety of scenarios and considering fuel, operating and capital costs, and

operating characteristics, as well as federal and state taxes and incentives. The reduction in the projected long-term natural gas prices in the 2017 Annual Fuel Forecast and, to a lesser extent, the increase in the estimated Kemper IGCC operating costs, negatively impact the updated project economic viability analysis.

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

2017 Accounting Order Request

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

2017 Rate Case

Mississippi Power continues to believe that all costs related to the Kemper IGCC have been prudently incurred in accordance with the requirements of the 2012 MPSC CPCN Order. Mississippi Power also recognizes significant areas of potential challenge during future regulatory proceedings (and any subsequent, related legal challenges) exist. As described further herein and under " Prudence ," " Lignite Mine and CO 2 Pipeline Facilities ," " Termination of Proposed Sale of Undivided Interest ," " Bonus Depreciation ," " Investment Tax Credits ," and " Section 174 Research and Experimental Deduction ," these challenges include, but are not limited to, prudence issues associated with capital costs, financing costs (AFUDC), and future operating costs net of chemical revenues; potential operating parameters; income tax issues; costs deferred as regulatory assets; and the 15% portion of the project previously contracted to SMEPA.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization of up to $1.0 billion of prudently-incurred costs was enacted into law in 2013. Mississippi Power expects to utilize this legislation to securitize prudently-incurred qualifying facility costs in excess of the certificated cost estimate of $2.4 billion . Qualifying facility costs include, but are not limited to, pre-construction costs, construction costs, regulatory costs, and accrued AFUDC. The Court's decision regarding the 2013 MPSC Rate Order did not impact Mississippi Power's ability to utilize alternate financing through securitization or the February 2013 legislation.

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

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

2015 Rate Case

On August 13, 2015, the Mississippi PSC approved Mississippi Power's request for interim rates, which presented an alternative rate proposal (In-Service Asset Proposal) designed to recover Mississippi Power's costs associated with the Kemper IGCC assets that are commercially operational and currently providing service to customers (the transmission facilities, combined cycle,

natural gas pipeline, and water pipeline) and other related costs. The interim rates were designed to collect approximately $159 million annually and became effective in September 2015, subject to refund and certain other conditions.

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

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

2013 MPSC Rate Order

In January 2013, Mississippi Power entered into a settlement agreement with the Mississippi PSC that was intended to establish the process for resolving matters regarding cost recovery related to the Kemper IGCC (2013 Settlement Agreement). Under the 2013 Settlement Agreement, Mississippi Power agreed to limit the portion of prudently-incurred Kemper IGCC costs to be included in retail rate base to the $2.4 billion certificated cost estimate, plus the Cost Cap Exceptions, but excluding AFUDC, and any other costs permitted or determined to be excluded from the $2.88 billion cost cap by the Mississippi PSC. In March 2013, the Mississippi PSC issued a rate order approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014 (2013 MPSC Rate Order) to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service, based on a mirror CWIP methodology (Mirror CWIP rate).

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

Because the 2013 MPSC Rate Order did not provide for the inclusion of CWIP in rate base as permitted by the Baseload Act, Mississippi Power continues to record AFUDC on the Kemper IGCC. Through December 31, 2016, AFUDC recorded since the original May 2014 estimated in-service date for the Kemper IGCC has totaled $398 million , which will continue to accrue at approximately $16 million per month until the remainder of the plant is placed in service. Mississippi Power has not recorded any AFUDC on Kemper IGCC costs in excess of the $2.88 billion cost cap, except for Cost Cap Exception amounts.

2012 MPSC CPCN Order

The 2012 MPSC CPCN Order included provisions relating to both Mississippi Power's recovery of financing costs during the course of construction of the Kemper IGCC and Mississippi Power's recovery of costs following the date the Kemper IGCC is placed in service. With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC CPCN Order provided for the establishment of operational cost and revenue parameters including availability factor, heat rate, lignite heat content, and chemical revenue based upon assumptions in Mississippi Power's petition for the CPCN. Mississippi Power expects the Mississippi PSC to apply operational parameters in connection with the 2017 Rate Case and future proceedings related to the operation of the Kemper IGCC. To the extent the Mississippi PSC determines the Kemper IGCC does not meet the operational parameters ultimately adopted by the Mississippi PSC or Mississippi Power incurs additional costs to satisfy such parameters, there could be a material adverse impact on the financial statements. See "Prudence" herein for additional information.

Regulatory Assets and Liabilities

Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC issued an accounting order in 2011 granting Mississippi Power the authority to defer all non-capital Kemper IGCC-related costs to a

regulatory asset through the in-service date, subject to review of such costs by the Mississippi PSC. Such costs include, but are not limited to, carrying costs on Kemper IGCC assets currently placed in service, costs associated with Mississippi PSC and MPUS consultants, prudence costs, legal fees, and operating expenses associated with assets placed in service.

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

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

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, Mississippi Power owns the lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site. The mine started commercial operation in June 2013.

In 2010, Mississippi Power executed a 40 -year management fee contract with Liberty Fuels Company, LLC (Liberty Fuels), a wholly-owned subsidiary of The North American Coal Corporation, which developed, constructed, and is operating and managing the mining operations. The contract with Liberty Fuels is effective through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and Mississippi Power has a contractual obligation to fund all reclamation activities. In addition to the obligation to fund the reclamation activities, Mississippi Power currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses.

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

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

Termination of Proposed Sale of Undivided Interest

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

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Litigation

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

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

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

Baseload Act

In 2008, the Baseload Act was signed by the Governor of Mississippi. The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently-incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. See "Rate Recovery of Kemper IGCC Costs" herein for additional information.

Bonus Depreciation

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

Investment Tax Credits

The IRS allocated $133 million (Phase I) and $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to Mississippi Power in connection with the Kemper IGCC. These tax credits were dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In addition, the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the Internal Revenue Code was also a requirement of the Phase II credits. As a result

of schedule extensions for the Kemper IGCC, the Phase I tax credits were recaptured in 2013 and the Phase II tax credits were recaptured in 2015.

Section 174 Research and Experimental Deduction

Southern Company reflected deductions for research and experimental (R&E) expenditures related to the Kemper IGCC in its federal income tax calculations since 2013 and has filed amended federal income tax returns for 2008 through 2013 to also include such deductions. The Kemper IGCC is based on first-of-a-kind technology, and Southern Company believes that a significant portion of the plant costs qualify as deductible R&E expenditures under Internal Revenue Code Section 174. In December 2016, Southern Company and the IRS reached a proposed settlement, subject to approval of the U.S. Congress Joint Committee on Taxation, resolving a methodology for these deductions. Due to the uncertainty related to this tax position, Southern Company had unrecognized tax benefits associated with these R&E deductions totaling approximately $464 million as of December 31, 2016 . See Note 5 under " Unrecognized Tax Benefits " for additional information. This matter is expected to be resolved in the next 12 months; however, the ultimate outcome of this matter cannot be determined at this time.

4. JOINT OWNERSHIP AGREEMENTS

Alabama Power owns an undivided interest in Units 1 and 2 at Plant Miller and related facilities jointly with PowerSouth Energy Cooperative, Inc. Georgia Power owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with one or more of the following entities: OPC, MEAG Power, the City of Dalton, Georgia, Florida Power & Light Company, and Jacksonville Electric Authority. In addition, Georgia Power has joint ownership agreements with OPC for the Rocky Mountain facilities. On August 31, 2016, Georgia Power sold its 33% ownership interest in the Intercession City combustion turbine unit to Duke Energy Florida, LLC. Southern Power owns an undivided interest in Plant Stanton Unit A and related facilities jointly with the Orlando Utilities Commission, Kissimmee Utility Authority, and Florida Municipal Power Agency.

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

Facility (Type)	Percent Ownership	Plant in Service	Accumulated Depreciation	CWIP
			(in millions)	
Plant Vogtle (nuclear) Units 1 and 2	45.7%	$ 3,545	$ 2,111	$ 74
Plant Hatch (nuclear)	50.1	1,297	585	81
Plant Miller (coal) Units 1 and 2	91.8	1,657	587	23
Plant Scherer (coal) Units 1 and 2	8.4	258	90	3
Plant Wansley (coal)	53.5	1,046	308	12
Rocky Mountain (pumped storage)	25.4	181	129	—
Plant Stanton (combined cycle) Unit A	65.0	155	58	—

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

Alabama Power and Georgia Power have contracted to operate and maintain their jointly-owned facilities, except for Rocky Mountain, as agents for their respective co-owners. Southern Power has a service agreement with SCS whereby SCS is responsible for the operation and maintenance of Plant Stanton Unit A. The companies' proportionate share of their plant operating expenses is included in the corresponding operating expenses in the statements of income and each company is responsible for providing its own financing.

Southern Company Gas has a 50% undivided ownership interest with The Williams Companies, Inc. in a 115 -mile pipeline facility being constructed in northwest Georgia. The CWIP balance representing Southern Company Gas' share of construction costs was approximately $124 million as of December 31, 2016 . Southern Company Gas also has an agreement to lease its 50% undivided ownership in the pipeline facility once it is placed in service, which is currently expected to be later in 2017. Under the lease, Southern Company Gas will receive approximately $26 million annually for an initial term of 25 years . The lessee will be responsible for maintaining the pipeline during the lease term and for providing service to transportation customers under its FERC-regulated tariff.

5. INCOME TAXES

Southern Company files a consolidated federal income tax return and various state income tax returns, some of which are combined or unitary. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. PowerSecure and Southern Company Gas became participants in the income tax allocation agreement as of May 9, 2016 and July 1, 2016, respectively. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2016	2015	2014
		(in millions)	
Federal —			
Current	**$ 1,184**	$ (177)	$ 175
Deferred	**(342)**	1,266	695
	842	1,089	870
State —			
Current	**(108)**	(33)	93
Deferred	**217**	138	14
	109	105	107
Total	**$ 951**	$ 1,194	$ 977

Net cash payments (refunds) for income taxes in 2016 , 2015 , and 2014 were $(148) million , $(9) million , and $272 million , respectively.

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

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

	2016	2015
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	**$ 15,392**	$ 12,767
Property basis differences	**2,708**	1,603
Leveraged lease basis differences	**314**	308
Employee benefit obligations	**737**	579
Premium on reacquired debt	**89**	95
Regulatory assets associated with employee benefit obligations	**1,584**	1,378
Regulatory assets associated with AROs	**1,781**	1,422
Other	**907**	793
Total	**23,512**	18,945
Deferred tax assets —		
Federal effect of state deferred taxes	**597**	479
Employee benefit obligations	**1,868**	1,720
Over recovered fuel clause	**66**	104
Other property basis differences	**401**	695
Deferred costs	**100**	83
ITC carryforward	**1,974**	770
Federal NOL carryforward	**1,084**	38
Unbilled revenue	**92**	111
Other comprehensive losses	**152**	85
AROs	**1,732**	1,482
Estimated Loss on Kemper IGCC	**484**	451
Deferred state tax assets	**266**	222
Other	**679**	443
Total	**9,495**	6,683
Valuation allowance	**(23)**	(4)
Total deferred income taxes	**14,040**	12,266
Portion included in accumulated deferred tax assets	**(52)**	(56)
Accumulated deferred income taxes	**$ 14,092**	$ 12,322

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

At December 31, 2016 , the tax-related regulatory assets to be recovered from customers were $1.6 billion . These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest.

At December 31, 2016 , the tax-related regulatory liabilities to be credited to customers were $219 million . These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized ITCs.

In accordance with regulatory requirements, deferred federal ITCs for the traditional electric operating companies are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $22 million in 2016 , $21 million in 2015 , and $22 million in 2014 . Southern Power's deferred federal ITCs are amortized to income tax expense over the life of the asset. Credits amortized in this manner amounted to $37 million in 2016 , $19 million in 2015 , and $11 million in 2014 . Also, Southern Power received cash

related to federal ITCs under the renewable energy incentives of $162 million and $74 million for the years ended December 31, 2015 and 2014 , respectively. No cash was received related to these incentives in 2016. Furthermore, the tax basis of the asset is reduced by 50% of the ITCs received, resulting in a net deferred tax asset. Southern Power has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation. The tax benefit of the related basis differences reduced income tax expense by $173 million in 2016 , $54 million in 2015 , and $48 million in 2014 . See " Unrecognized Tax Benefits " below for further information.

Tax Credit Carryforwards

At December 31, 2016 , Southern Company had federal ITC and PTC carryforwards (primarily related to Southern Power) which are expected to result in $1.8 billion of federal income tax benefits. The federal ITC carryforwards begin expiring in 2032 but are expected to be fully utilized by 2022. The PTC carryforwards begin expiring in 2036 but are expected to be fully utilized by 2022. The acquisition of additional renewable projects and carrying back the federal NOL, as well as potential tax reform legislation on existing renewable incentives, could further delay existing tax credit carryforwards. The ultimate outcome of these matters cannot be determined at this time.

Additionally, Southern Company had state ITC carryforwards for the state of Georgia totaling $202 million , which begin expiring in 2020 but are expected to be fully utilized.

Net Operating Loss

At December 31, 2016, Southern Company had a consolidated federal NOL carryforward of $3 billion , of which $2.8 billion is projected for the 2016 tax year. The federal NOL will begin expiring in 2033. However, portions of the NOL are expected to be carried back to prior tax years and forward to future tax years. The ultimate outcome of this matter cannot be determined at this time.

At December 31, 2016, the state NOL carryforwards for Southern Company's subsidiaries were as follows:

Jurisdiction	NOL Carryforwards	Net State Income Tax Benefit	Tax Year NOL Begins Expiring
	(in millions)		
Mississippi	$ 3,448	$ 112	2032
Oklahoma	839	31	2036
Georgia	685	25	2019
New York	229	11	2036
New York City	209	12	2036
Florida	198	7	2034
Other states	146	5	Various
Total	$ 5,754	$ 203	

Effective Tax Rate

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

	2016	2015	2014
Federal statutory rate	**35.0 %**	35.0 %	35.0 %
State income tax, net of federal deduction	**2.1**	1.9	2.3
Employee stock plans dividend deduction	**(1.2)**	(1.2)	(1.4)
Non-deductible book depreciation	**0.9**	1.2	1.4
AFUDC-Equity	**(2.0)**	(2.2)	(2.9)
ITC basis difference	**(5.0)**	(1.5)	(1.6)
Federal PTCs	**(1.2)**	—	—
Amortization of ITC	**(0.9)**	(0.5)	(0.5)
Other	**(0.4)**	0.2	0.2
Effective income tax rate	**27.3 %**	32.9 %	32.5 %

Southern Company's effective tax rate is typically lower than the statutory rate due to employee stock plans' dividend deduction, non-taxable AFUDC equity, and federal income tax benefits from ITCs and PTCs.

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

Unrecognized Tax Benefits

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

	2016	2015	2014
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 433**	$ 170	$ 7
Tax positions increase from current periods	**45**	43	64
Tax positions increase from prior periods	**21**	240	102
Tax positions decrease from prior periods	**(15)**	(20)	(3)
Balance at end of year	**$ 484**	$ 433	$ 170

The tax positions increase from current and prior periods for 2016 and 2015 relate primarily to deductions for R&E expenditures associated with the Kemper IGCC and federal income tax benefits from deferred ITCs. See Note 3 under " Integrated Coal Gasification Combined Cycle " and " Section 174 Research and Experimental Deduction " herein for more information. The tax positions decrease from prior periods for 2016 and 2015 relates to federal income tax benefits from deferred ITCs.

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

	2016	2015	2014
		(in millions)	
Tax positions impacting the effective tax rate	**$ 20**	$ 10	$ 10
Tax positions not impacting the effective tax rate	**464**	423	160
Balance of unrecognized tax benefits	**$ 484**	$ 433	$ 170

The tax positions impacting the effective tax rate primarily relate to federal deferred income tax credits and Southern Company's estimate of the uncertainty related to the amount of those benefits. If these tax positions are not able to be recognized due to a federal audit adjustment in the amount that has been estimated, the amount of tax credit carryforwards discussed above would be reduced by approximately $92 million . The tax positions not impacting the effective tax rate for 2016 , 2015 , and 2014 relate to deductions for R&E expenditures associated with the Kemper IGCC. See " Section 174 Research and Experimental Deduction "

herein for more information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Accrued interest for all tax positions other than the Section 174 R&E deductions was immaterial for all years presented.

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

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

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

Section 174 Research and Experimental Deduction

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

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

6. FINANCING

Long-Term Debt Payable to an Affiliated Trust

Alabama Power has formed a wholly-owned trust subsidiary for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to Alabama Power through the issuance of junior subordinated notes totaling $206 million as of December 31, 2016 and 2015 , which constitute substantially all of the assets of this trust and are reflected in the balance sheets as long-term debt payable. Alabama Power considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trust's payment obligations with respect to these securities. At December 31, 2016 and 2015 , trust preferred securities of $200 million were outstanding.

Securities Due Within One Year

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

	2016	2015
	(in millions)	
Senior notes	**$ 1,995**	$ 1,810
Other long-term debt	**485**	829
Pollution control revenue bonds (*)	**76**	4
Capitalized leases	**32**	32
Unamortized debt issuance expense	**(1)**	(1)
Total	**$ 2,587**	$ 2,674

(*) Includes $40 million of pollution control revenue bonds classified as short-term since they are variable rate demand obligations that are supported by short-term credit facilities; however, the final maturity date is in 2028.

Maturities through 2021 applicable to total long-term debt are as follows: $2.6 billion in 2017 ; $3.9 billion in 2018 ; $3.2 billion in 2019 ; $1.4 billion in 2020 ; and $3.1 billion in 2021 .

Bank Term Loans

Southern Company and certain of its subsidiaries have entered into various bank term loan agreements. At December 31, 2016 , Southern Company, Alabama Power, Gulf Power, Mississippi Power, and Southern Power Company had outstanding bank term loans totaling $400 million , $45 million , $100 million , $1.2 billion , and $380 million , respectively, of which $2.0 billion are reflected in the statements of capitalization as long-term debt and $100 million are reflected in the balance sheet as notes payable. At December 31, 2015 , Southern Company, Mississippi Power, and Southern Power Company had outstanding bank term loans totaling $400 million , $900 million , and $400 million , respectively .

In March 2016, Alabama Power entered into three bank term loan agreements with maturity dates of March 2021, in an aggregate principal amount of $45 million , one of which bears interest at 2.38% per annum and two of which bear interest based on three-month LIBOR.

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

In May 2016, Gulf Power entered into an 11 -month floating rate bank loan bearing interest based on one-month LIBOR. This short-term loan was for $100 million aggregate principal amount and the proceeds were used to repay existing indebtedness and for working capital and other general corporate purposes.

In September 2016, Southern Power Company repaid $80 million of an outstanding $400 million floating rate bank loan and extended the maturity date of the remaining $320 million from September 2016 to September 2018. In addition, Southern Power Company entered into a $60 million aggregate principal amount floating rate bank loan bearing interest based on one-month LIBOR due September 2017. The proceeds were used to repay existing indebtedness and for other general corporate purposes.

The outstanding bank loans as of December 31, 2016 have covenants that limit debt levels to a percentage of total capitalization. The percentage is 70% for Southern Company and 65% for Alabama Power, Gulf Power, Mississippi Power, and Southern Power Company, as defined in the agreements. For purposes of these definitions, debt excludes any long-term debt payable to affiliated trusts, other hybrid securities, and, for Southern Company and Mississippi Power, any securitized debt relating to the securitization of certain costs of the Kemper IGCC. Additionally, for Southern Company and Southern Power Company, for purposes of these definitions, debt excludes any project debt incurred by certain subsidiaries of Southern Power Company to the extent such debt is non-recourse to Southern Power Company and capitalization excludes the capital stock or other equity attributable to such subsidiary. At December 31, 2016 , each of Southern Company, Alabama Power, Gulf Power, Mississippi Power, and Southern Power Company was in compliance with its debt limits.

DOE Loan Guarantee Borrowings

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

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

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

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

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

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

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

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

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

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

Senior Notes

Southern Company and its subsidiaries issued a total of $13.3 billion of senior notes in 2016 . Southern Company issued $8.5 billion and its subsidiaries issued a total of $4.8 billion . These amounts include senior notes issued by Southern Company Gas subsequent to the Merger. The proceeds of Southern Company's issuances were used to fund a portion of the consideration for the Merger and related transaction costs and for general corporate purposes. Except as described below, the proceeds of Southern Company's subsidiaries' issuances were used to repay long-term indebtedness, to repay short-term indebtedness, and for other general corporate purposes, including the applicable subsidiaries' continuous construction programs, and, for Southern Power, its growth strategy. Certain of Georgia Power's and Southern Power's issuances were allocated to eligible renewable energy expenditures. The proceeds of Southern Company Gas' issuances were primarily used to repay a $360 million promissory note issued to Southern Company for the purpose of funding a portion of the purchase price for a 50% equity interest in Southern Natural Gas Company, L.L.C. (SNG), to fund the purchase of Piedmont Natural Gas Company, Inc.'s (Piedmont) interest in SouthStar Energy Services, LLC (SouthStar), and to make a voluntary contribution to Southern Company Gas' pension plan. See Note 12 under " Southern Company – Investment in Southern Natural Gas " and " – Acquisition of Remaining Interest in SouthStar " for additional information.

At December 31, 2016 and 2015 , Southern Company and its subsidiaries had a total of $33.0 billion and $19.1 billion , respectively, of senior notes outstanding. At December 31, 2016 and 2015 , Southern Company had a total of $10.3 billion and $2.4 billion , respectively, of senior notes outstanding. These amounts include senior notes due within one year.

Subsequent to December 31, 2016, Alabama Power repaid at maturity $200 million aggregate principal amount of its Series 2007A 5.55% Senior Notes due February 1, 2017.

Since Southern Company is a holding company, the right of Southern Company and, hence, the right of creditors of Southern Company (including holders of Southern Company senior notes) to participate in any distribution of the assets of any subsidiary of Southern Company, whether upon liquidation, reorganization or otherwise, is subject to prior claims of creditors and preferred and preference stockholders of such subsidiary.

Junior Subordinated Notes

At December 31, 2016 and 2015 , Southern Company had a total of $2.4 billion and $1.0 billion , respectively, of junior subordinated notes outstanding.

In September 2016, Southern Company issued $800 million aggregate principal amount of Series 2016A 5.25% Junior Subordinated Notes due October 1, 2076. The proceeds were used to repay short-term indebtedness that was incurred to repay at maturity $500 million aggregate principal amount of Southern Company's Series 2011A 1.95% Senior Notes due September 1, 2016 and for other general corporate purposes.

In December 2016, Southern Company issued $550 million aggregate principal amount of Series 2016B Junior Subordinated Notes due March 15, 2057, which bear interest at a fixed rate of 5.50% per year up to, but not including, March 15, 2022. From, and including, March 15, 2022, the Series 2016B Junior Subordinated Notes will bear interest at a floating rate based on three-month LIBOR. The proceeds were used for general corporate purposes.

Pollution Control Revenue Bonds

Pollution control revenue bond obligations represent loans to the traditional electric operating companies from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. In some cases, the pollution control revenue bond obligations represent obligations under installment sales agreements with respect to facilities constructed with the proceeds of revenue bonds issued by public authorities. The traditional electric operating companies had $3.3 billion of outstanding pollution control revenue bond obligations at December 31, 2016 and 2015 , which includes pollution control revenue bonds due within one year. The traditional electric operating companies are required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Plant Daniel Revenue Bonds

In 2011, in connection with Mississippi Power's election under its operating lease of Plant Daniel Units 3 and 4 to purchase the assets, Mississippi Power assumed the obligations of the lessor related to $270 million aggregate principal amount of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 20, 2021, issued for the benefit of the lessor. See " Assets Subject to Lien " herein for additional information.

Gas Facility Revenue Bonds

Pivotal Utility Holdings, Inc., a subsidiary of Southern Company Gas, is party to a series of loan agreements with the New Jersey Economic Development Authority and Brevard County, Florida under which five series of gas facility revenue bonds have been issued with maturities ranging from 2022 to 2033. These revenue bonds are issued by state agencies or counties to investors, and proceeds from the issuance then are loaned to Southern Company Gas. The amount of gas facility revenue bonds outstanding at December 31, 2016 was $200 million .

Other Revenue Bonds

Other revenue bond obligations represent loans to Mississippi Power from a public authority of funds derived from the sale by such authority of revenue bonds issued to finance a portion of the costs of constructing the Kemper IGCC and related facilities.

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

First Mortgage Bonds

Nicor Gas, a subsidiary of Southern Company Gas, had $625 million of first mortgage bonds outstanding at December 31, 2016 . These bonds have been issued with maturities ranging from 2019 to 2038. Substantially all of Nicor Gas' properties are subject to the lien of the indenture securing these first mortgage bonds. See " Assets Subject to Lien " herein for additional information.

Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as property, plant, and equipment and the related obligations are classified as long-term debt.

In 2013, Mississippi Power entered into a nitrogen supply agreement for the air separation unit of the Kemper IGCC, which resulted in a capital lease obligation at December 31, 2016 and 2015 of approximately $74 million and $77 million , respectively, with an annual interest rate of 4.9% for both years. Amortization of the capital lease asset for the air separation unit will begin when the Kemper IGCC is placed in service. See Note 3 under " Integrated Coal Gasification Combined Cycle " for additional information regarding the Kemper IGCC.

At December 31, 2016 and 2015 , the capitalized lease obligations for Georgia Power's corporate headquarters building were $28 million and $35 million , respectively, with an annual interest rate of 7.9% for both years.

At December 31, 2016 and 2015 , Alabama Power had capitalized lease obligations of $4 million and $5 million , respectively, for a natural gas pipeline with an annual interest rate of 6.9% .

At December 31, 2016 and 2015 , a subsidiary of Southern Company had capital lease obligations of approximately $29 million and $30 million , respectively, for certain computer equipment including desktops, laptops, servers, printers, and storage devices with annual interest rates that range from 1.4% to 3.4% .

Assets Subject to Lien

Each of Southern Company's subsidiaries is organized as a legal entity, separate and apart from Southern Company and its other subsidiaries. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

Gulf Power has granted one or more liens on certain of its property in connection with the issuance of certain series of pollution control revenue bonds with an aggregate outstanding principal amount of $41 million as of December 31, 2016 .

The revenue bonds assumed in conjunction with Mississippi Power's purchase of Plant Daniel Units 3 and 4 are secured by Plant Daniel Units 3 and 4 and certain related personal property. See " Plant Daniel Revenue Bonds " herein for additional information.

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

The first mortgage bonds issued by Nicor Gas are secured by substantially all of Nicor Gas' properties. See " First Mortgage Bonds " herein for additional information.

During 2016, in accordance with its overall growth strategy, Southern Power acquired the Mankato project. Under the terms of the remaining 10 -year PPA and the 20 -year expansion PPA, approximately $408 million of assets, primarily related to property, plant, and equipment, are subject to lien at December 31, 2016. See Note 12 under "Southern Power" for additional information.

Bank Credit Arrangements

At December 31, 2016 , committed credit arrangements with banks were as follows:

	Expires					Executable Term Loans		Expires Within One Year	
Company	**2017**	**2018**	**2020**	**Total**	**Unused**	**One Year**	**Two Years**	**Term Out**	**No Term Out**
		(in millions)		*(in millions)*		*(in millions)*		*(in millions)*	
Southern Company [(a)]	$ —	$ 1,000	$ 1,250	$ 2,250	$ 2,250	$ —	$ —	$ —	$ —
Alabama Power	35	500	800	1,335	1,335	—	—	—	35
Georgia Power	—	—	1,750	1,750	1,732	—	—	—	—
Gulf Power	85	195	—	280	280	45	—	25	60
Mississippi Power	173	—	—	173	150	—	13	13	160
Southern Power Company [(b)]	—	—	600	600	522	—	—	—	—
Southern Company Gas [(c)]	75	1,925	—	2,000	1,949	—	—	—	75
Other	55	—	—	55	55	20	—	20	35
Southern Company Consolidated	$ 423	$ 3,620	$ 4,400	$ 8,443	$ 8,273	$ 65	$ 13	$ 58	$ 365

(a) Represents the Southern Company parent entity.

(b) Excludes credit agreements (Project Credit Facilities) assumed with the acquisition of certain solar facilities, which were non-recourse to Southern Power Company, the proceeds of which were used to finance project costs related to such solar facilities. See Note 12 under " Southern Power " for additional information. Also excludes a $120 million continuing letter of credit facility entered into by Southern Power in December 2016 for standby letters of credit expiring in 2019. At December 31, 2016, the total amount available under the letter of credit facility was $82 million .

(c) Southern Company Gas, as the parent entity, guarantees the obligations of Southern Company Gas Capital, which is the borrower of $1.3 billion of these arrangements. Southern Company Gas' committed credit arrangements also include $700 million for which Nicor Gas is the borrower and which is restricted for working capital needs of Nicor Gas.

Most of the bank credit arrangements require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than $^{1}/_{4}$ of 1% for Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas. Compensating balances are not legally restricted from withdrawal.

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

Southern Company's, Southern Company Gas', and Nicor Gas' credit arrangements contain covenants that limit debt levels to 70% of total capitalization, as defined in the agreements, and most of these other bank credit arrangements contain covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts and, in certain arrangements, other hybrid securities, and, for Southern Company and Mississippi Power, any securitized debt relating to the securitization of certain costs of the Kemper IGCC. Additionally, for Southern Company and Southern Power Company, for purposes of these definitions, debt excludes any project debt incurred by certain subsidiaries of Southern Power Company to the extent such debt is non-recourse to Southern Power Company and capitalization excludes the capital stock or other equity attributable to such subsidiaries. At December 31, 2016 , Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas were each in compliance with their respective debt limit covenants.

A portion of the $8.3 billion unused credit with banks is allocated to provide liquidity support to the pollution control revenue bonds of the traditional electric operating companies and the commercial paper programs of Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas. The amount of variable rate pollution control revenue bonds of the traditional electric operating companies outstanding requiring liquidity support as of December 31, 2016 was approximately $1.9 billion . In addition, at December 31, 2016 , the traditional electric operating companies had approximately $0.4 billion of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed

bank credit arrangements described above. Commercial paper and short-term bank term loans are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period	
	Amount Outstanding	**Weighted Average Interest Rate**
	(in millions)	
December 31, 2016:		
Commercial paper	**$ 1,909**	**1.1%**
Short-term bank debt	**123**	**1.7%**
Total	**$ 2,032**	**1.1%**
December 31, 2015:		
Commercial paper	$ 740	0.7%
Short-term bank debt	500	1.4%
Total	$ 1,240	0.9%

In addition to the short-term borrowings in the table above, Southern Power's subsidiary Project Credit Facilities had total amounts outstanding of $209 million and $137 million at a weighted average interest rate of 2.1% and 2.0% as of December 31, 2016 and 2015 , respectively. The amounts outstanding as of December 31, 2016 under the Project Credit Facilities were fully repaid subsequent to December 31, 2016 .

Redeemable Preferred Stock of Subsidiaries

Each of the traditional electric operating companies has issued preferred and/or preference stock. The preferred stock of Alabama Power and Mississippi Power contains a feature that allows the holders to elect a majority of such subsidiary's board of directors if preferred dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of Alabama Power and Mississippi Power, this preferred stock is presented as "Redeemable Preferred Stock of Subsidiaries" in a manner consistent with temporary equity under applicable accounting standards. The preferred and preference stock at Georgia Power and the preference stock at Alabama Power and Gulf Power do not contain such a provision. As a result, under applicable accounting standards, the preferred and preference stock at Georgia Power and the preference stock at Alabama Power and Gulf Power are presented as "Preferred and Preference Stock of Subsidiaries," a separate component of "Stockholders' Equity," on Southern Company's balance sheets, statements of capitalization, and statements of stockholders' equity.

The following table presents changes during the year in redeemable preferred stock of subsidiaries for Southern Company:

	Redeemable Preferred Stock of Subsidiaries
	(in millions)
Balance at December 31, 2013	$ 375
Issued	—
Redeemed	—
Balance at December 31, 2014	375
Issued	—
Redeemed	(262)
Other	5
Balance at December 31, 2015	118
Issued	—
Redeemed	—
Balance at December 31, 2016	**$ 118**

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of the generating plants, the Southern Company system has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2016 , 2015 , and 2014 , the traditional electric operating companies and Southern Power incurred fuel expense of $4.4 billion , $4.8 billion , and $6.0 billion , respectively, the majority of which was purchased under long-term commitments. Southern Company expects that a substantial amount of the Southern Company system's future fuel needs will continue to be purchased under long-term commitments.

In addition, the Southern Company system has entered into various long-term commitments for the purchase of capacity and electricity, some of which are accounted for as operating leases or have been used by a third party to secure financing. Total capacity expense under PPAs accounted for as operating leases was $232 million , $227 million , and $198 million for 2016 , 2015 , and 2014 , respectively.

Estimated total obligations under these commitments at December 31, 2016 were as follows:

	Operating Leases (*)	Other
	(in millions)	
2017	$ 242	$ 8
2018	246	7
2019	249	6
2020	246	5
2021	249	5
2022 and thereafter	1,041	43
Total	$ 2,273	$ 74

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

Pipeline Charges, Storage Capacity, and Gas Supply

Pipeline charges, storage capacity, and gas supply include charges recoverable through a natural gas cost recovery mechanism, or alternatively, billed to marketers selling retail natural gas, as well as demand charges associated with Southern Company Gas' wholesale gas services. The gas supply balance includes amounts for gas commodity purchase commitments associated with Southern Company Gas' gas marketing services of 33 million mmBtu at floating gas prices calculated using forward natural gas prices at December 31, 2016 and valued at $106 million . Southern Company Gas provides guarantees to certain gas suppliers for certain of its subsidiaries in support of payment obligations.

Expected future contractual obligations for pipeline charges, storage capacity, and gas supply that are not recognized on the balance sheets as of December 31, 2016 were as follows:

	Pipeline Charges, Storage Capacity, and Gas Supply
	(in millions)
2017	$ 822
2018	602
2019	447
2020	394
2021	352
2022 and thereafter	2,591
Total	$ 5,208

Operating Leases

The Southern Company system has operating lease agreements with various terms and expiration dates. Total rent expense was $169 million , $130 million , and $118 million for 2016 , 2015 , and 2014 , respectively. Southern Company includes any step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term.

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

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
		(in millions)	
2017	$ 31	$ 121	$ 152
2018	19	115	134
2019	10	103	113
2020	10	90	100
2021	8	82	90
2022 and thereafter	11	1,184	1,195
Total	$ 89	$ 1,695	$ 1,784

For the traditional electric operating companies, a majority of the barge and railcar lease expenses are recoverable through fuel cost recovery provisions.

In addition to the above rental commitments, Alabama Power and Georgia Power have obligations upon expiration of certain railcar leases with respect to the residual value of the leased property. These leases have terms expiring through 2024 with maximum obligations under these leases of $44 million . At the termination of the leases, the lessee may renew the lease, exercise its purchase option, or the property can be sold to a third party. Alabama Power and Georgia Power expect that the fair market value of the leased property would substantially reduce or eliminate the payments under the residual value obligations.

Guarantees

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

As discussed above under "Operating Leases," Alabama Power and Georgia Power have entered into certain residual value guarantees.

8. COMMON STOCK

Stock Issued

In May and August 2016, Southern Company issued an aggregate of 50.8 million shares of common stock in underwritten offerings for an aggregate purchase price of approximately $2.5 billion . Of the 50.8 million shares, approximately 2.6 million were issued from treasury and the remainder were newly issued shares. The proceeds were used to fund a portion of the consideration for the Merger and related transaction costs, to fund a portion of the purchase price for the SNG investment and related transaction costs, and for other general corporate purposes.

During the fourth quarter 2016, Southern Company issued approximately 8.0 million shares of common stock through at-the-market issuances pursuant to sales agency agreements related to Southern Company's continuous equity offering program and received cash proceeds of approximately $381 million , net of $3 million in fees and commissions.

In addition, during 2016 , Southern Company issued approximately 20 million shares of common stock primarily through employee equity compensation plans and received proceeds of approximately $874 million .

Shares Reserved

At December 31, 2016 , a total of 94 million shares were reserved for issuance pursuant to the Southern Investment Plan, the Employee Savings Plan, the Outside Directors Stock Plan, and the Omnibus Incentive Compensation Plan (which includes stock

options and performance share units as discussed below). Of the total 94 million shares reserved, there were 14 million shares of common stock remaining available for awards under the Omnibus Incentive Compensation Plan as of December 31, 2016 .

Stock-Based Compensation

Stock-based compensation primarily in the form of performance share units may be granted through the Omnibus Incentive Compensation Plan to a large segment of Southern Company system employees ranging from line management to executives. As of December 31, 2016 , there were 5,229 current and former employees participating in the stock option and performance share unit programs.

In conjunction with the Merger, stock-based compensation in the form of Southern Company restricted stock and performance share units was also granted to certain executives of Southern Company Gas through the Southern Company Omnibus Incentive Compensation Plan.

Stock Options

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

The estimated fair values of stock options granted were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. Southern Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	2014
Expected volatility	14.6%
Expected term *(in years)*	5
Interest rate	1.5%
Dividend yield	4.9%
Weighted average grant-date fair value	$2.20

Southern Company's activity in the stock option program for 2016 is summarized below:

	Shares Subject to Option	**Weighted Average Exercise Price**	
Outstanding at December 31, 2015	35,749,906	$	40.96
Exercised	11,120,613		40.26
Cancelled	43,429		41.38
Outstanding at December 31, 2016	**24,585,864**	**$**	**41.28**
Exercisable at December 31, 2016	**21,133,320**	**$**	**41.26**

The number of stock options vested, and expected to vest in the future, as of December 31, 2016 was not significantly different from the number of stock options outstanding at December 31, 2016 as stated above. As of December 31, 2016 , the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years , respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $195 million and $168 million , respectively.

For the years ended December 31, 2016 , 2015 , and 2014 , total compensation cost for stock option awards recognized in income was $3 million , $6 million , and $27 million , respectively, with the related tax benefit also recognized in income of $1 million , $2 million , and $10 million , respectively. As of December 31, 2016 , the total unrecognized compensation cost related to stock option awards not yet vested was immaterial.

The total intrinsic value of options exercised during the years ended December 31, 2016 , 2015 , and 2014 was $120 million , $48 million , and $125 million , respectively. The actual tax benefit for the tax deductions from stock option exercises totaled $46 million , $19 million , and $48 million for the years ended December 31, 2016 , 2015 , and 2014 , respectively. Prior to the adoption of ASU 2016-09, the excess tax benefits related to the exercise of stock options were recognized in Southern 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.

Southern Company has a policy of issuing shares to satisfy share option exercises. Cash received from issuances related to option exercises under the share-based payment arrangements for the years ended December 31, 2016 , 2015 , and 2014 was $448 million , $154 million , and $400 million , respectively.

Performance Share Units

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

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

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

In determining the fair value of the TSR-based awards issued to employees, the expected volatility was based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the awards. The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of performance share award units granted:

Year Ended December 31	**2016**	2015	2014
Expected volatility	**15.0%**	12.9%	12.6%
Expected term *(in years)*	**3**	3	3
Interest rate	**0.8%**	1.0%	0.6%
Annualized dividend rate (*)	**N/A**	N/A	$2.03
Weighted average grant-date fair value	**$45.06**	$46.38	$37.54

N/A - Not applicable

(*) Beginning in 2015, cash dividends paid on Southern Company's common stock are accumulated and payable in additional shares of Southern Company's common stock at the end of the three -year performance period and are embedded in the grant date fair value which equates to the grant date stock price.

The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2016 and 2015 was $48.87 and $47.75 , respectively.

Total unvested performance share units outstanding as of December 31, 2015 were 2,480,392 . During 2016 , 1,717,167 performance share units were granted, 937,121 performance share units were vested, and 35,899 performance share units were forfeited, resulting in 3,224,539 unvested performance share units outstanding at December 31, 2016 . No shares were issued in January 2017 for the three -year performance and vesting period ended December 31, 2016 .

For the years ended December 31, 2016 , 2015 , and 2014 , total compensation cost for performance share units recognized in income was $96 million , $88 million , and $33 million , respectively, with the related tax benefit also recognized in income of $37 million , $34 million , and $13 million , respectively. As of December 31, 2016 , $32 million of total unrecognized compensation cost related to performance share award units will be recognized over a weighted-average period of approximately 22 months .

Southern Company Gas Restricted Stock Awards

At the effective time of the Merger, each outstanding award of existing Southern Company Gas performance share units was converted into an award of Southern Company's restricted stock units (RSU). Under the terms of the RSU awards, the employees received Southern Company stock when they satisfy the requisite service period by being continuously employed through the original three -year vesting schedule of the award being replaced. Southern Company issued 742,461 RSUs with a grant-date fair value of $53.83 , based on the closing stock price of Southern Company common stock on the date of the grant. As a portion of the fair value of the award related to pre-combination service, the grant date fair value was allocated to pre- or post-combination service and accounted for as Merger consideration or compensation cost, respectively. Approximately $13 million of the grant date fair value was allocated to Merger consideration.

As of December 31, 2016, total compensation cost and related tax benefit for RSUs recognized in income was $13 million and $4 million , respectively. As of December 31, 2016, $12 million of total unrecognized compensation cost related to RSUs is expected to be recognized over a weighted-average period of approximately 20 months .

Southern Company Gas Change in Control Awards

Southern Company awarded performance share units to certain Southern Company Gas employees who continued their employment with the Southern Company in lieu of certain change in control benefits the employee was entitled to receive following the Merger (change in control awards). Shares of Southern Company common stock and/or cash equal to the dollar value of the change in control benefit will vest and be issued one-third each year as long as the employee remains in service with Southern Company or its subsidiaries at each vest date. In addition to the change in control benefit, Southern Company common stock could be issued to the employees at the end of a performance period based on achievement of certain Southern Company common stock price metrics, as well performance goals established by the Compensation Committee of the Southern Company Board of Directors (achievement shares).

The change in control benefits are accounted for as a liability award with the fair value equal to the guaranteed dollar value of the change in control benefit. The grant-date fair value of the achievement portion of the award was determined using a Monte Carlo simulation model to estimate the number of achievement shares expected to vest based on the Southern Company common stock price. The expected payout is reevaluated annually with expense recognized to date increased or decreased proportionately based on the expected performance. The compensation expense ultimately recognized for the achievement shares will be based on the actual performance.

As of December 31, 2016, total compensation cost and related tax benefit for the change in control awards recognized in income was immaterial. As of December 31, 2016, approximately $20 million of total unrecognized compensation cost related to change in control awards is expected to be recognized over a weighted-average period of approximately 23 months .

Diluted Earnings Per Share

For Southern Company, the only difference in computing basic and diluted EPS is attributable to awards outstanding under the stock option and performance share plans. The effect of both stock options and performance share award units was determined using the treasury stock method. Shares used to compute diluted EPS were as follows:

	Average Common Stock Shares		
	2016	2015	2014
		(in millions)	
As reported shares	**951**	910	897
Effect of options and performance share award units	**7**	4	4
Diluted shares	**958**	914	901

Prior to the adoption of ASU 2016-09, the effect of options and performance share award units included the assumed impacts of any excess tax benefits from the exercise of all "in the money" outstanding share based awards. In accordance with the new guidance, no prior year information was adjusted. Stock options and performance share award units that were not included in the diluted EPS calculation because they were anti-dilutive were immaterial as of December 31, 2016 and 2015 .

Common Stock Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2016 , consolidated retained earnings included $7.0 billion of undistributed retained earnings of the subsidiaries.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), Alabama Power and Georgia Power maintain agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the companies' nuclear power plants. The Act provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. A company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for Alabama Power and Georgia Power, based on its ownership and buyback interests in all licensed reactors, is $255 million and $247 million , respectively, per incident, but not more than an aggregate of $38 million and $37 million , respectively, per company to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years . The next scheduled adjustment is due no later than September 10, 2018. See Note 4 for additional information on joint ownership agreements.

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

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

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

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The maximum annual assessments for Alabama Power and Georgia Power as of December 31, 2016 under the NEIL policies would be $53 million and $82 million , respectively.

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

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

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

10. FAIR VALUE MEASUREMENTS

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

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

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

NOTES (continued)
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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 [(a)(b)]	$ 338	$ 333	$ —	$ —	$ 671
Interest rate derivatives	—	14	—	—	14
Nuclear decommissioning trusts: [(c)]					
Domestic equity	589	73	—	—	662
Foreign equity	48	168	—	—	216
U.S. Treasury and government agency securities	—	92	—	—	92
Municipal bonds	—	73	—	—	73
Corporate bonds	22	310	—	—	332
Mortgage and asset backed securities	—	183	—	—	183
Private equity	—	—	—	20	20
Other	11	15	—	—	26
Cash equivalents	1,172	—	—	—	1,172
Other investments	9	—	1	—	10
Total	$ 2,189	$ 1,261	$ 1	$ 20	$ 3,471
Liabilities:					
Energy-related derivatives [(a)(b)]	$ 345	$ 285	$ —	$ —	$ 630
Interest rate derivatives	—	29	—	—	29
Foreign currency derivatives	—	58	—	—	58
Contingent consideration	—	—	18	—	18
Total	$ 345	$ 372	$ 18	$ —	$ 735

(a) Energy-related derivatives exclude $4 million associated with certain weather derivatives accounted for based on intrinsic value rather than fair value.

(b) Energy-related derivatives exclude cash collateral of $62 million .

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

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

	Fair Value Measurements Using				
As of December 31, 2015:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Assets:					
Energy-related derivatives	$ —	$ 7	$ —	$ —	$ 7
Interest rate derivatives	—	22	—	—	22
Nuclear decommissioning trusts: [*]					
Domestic equity	541	69	—	—	610
Foreign equity	47	160	—	—	207
U.S. Treasury and government agency securities	—	152	—	—	152
Municipal bonds	—	64	—	—	64
Corporate bonds	11	278	—	—	289
Mortgage and asset backed securities	—	145	—	—	145
Private equity	—	—	—	17	17
Other	16	9	—	—	25
Cash equivalents	790	—	—	—	790
Other investments	9	—	1	—	10
Total	$ 1,414	$ 906	$ 1	$ 17	$ 2,338
Liabilities:					
Energy-related derivatives	$ —	$ 220	$ —	$ —	$ 220
Interest rate derivatives	—	30	—	—	30
Total	$ —	$ 250	$ —	$ —	$ 250

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

Valuation Methodologies

The energy-related derivatives primarily consist of exchange-traded and 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 fair value of cross-currency swaps reflects the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future foreign currency exchange rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and discount rates. The interest rate derivatives and cross-currency swaps are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 11 for additional information on how these derivatives are used.

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. For fair value measurements of the investments within the nuclear decommissioning trusts, external pricing vendors are designated for each asset class with each security specifically assigned a primary pricing source. For

investments held within commingled funds, fair value is determined at the end of each business day through the net asset value, which is established by obtaining the underlying securities' individual prices from the primary pricing source. A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, fixed income market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information, including live trading levels and pricing analysts' judgments, are also obtained when available. See Note 1 under " Nuclear Decommissioning " for additional information.

Southern Power has contingent payment obligations related to certain acquisitions whereby Southern Power is obligated to pay generation-based payments to the seller over a 10 -year period beginning at the commercial operation date. The obligation is measured at fair value using significant inputs such as forecasted facility generation in MW-hours, a fixed dollar amount per MW-hour, and a discount rate, and is evaluated periodically. The fair value of contingent consideration reflects the net present value of expected payments and any change arising from forecasted generation is expected to be immaterial.

"Other investments" include investments that are not traded in the open market. The fair value of these investments have been determined based on market factors including comparable multiples and the expectations regarding cash flows and business plan executions.

As of December 31, 2016 and 2015 , the fair value measurements of private equity investments held in the nuclear decommissioning trust that are calculated at net asset value per share (or its equivalent) as a practical expedient, as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
	(in millions)			
As of December 31, 2016	**$ 20**	**$ 25**	**Not Applicable**	**Not Applicable**
As of December 31, 2015	$ 17	$ 28	Not Applicable	Not Applicable

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

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

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt, including securities due within one year:		
2016	**$ 45,080**	**$ 46,286**
2015	$ 27,216	$ 27,913

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates available to Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, Southern Company Gas, and Nicor Gas.

11. DERIVATIVES

The Southern Company system is exposed to market risks, including commodity price risk, interest rate risk, weather risk, and occasionally foreign currency exchange rate risk. To manage the volatility attributable to these exposures, each company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to each company's policies in areas such as counterparty exposure and risk management practices. Each company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a 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. The cash impacts of settled foreign currency derivatives are classified as operating or financing activities to correspond with classification of the hedged interest or principal, respectively. See Note 1 under " Financial Instruments " for additional information.

Energy-Related Derivatives

Southern Company and certain subsidiaries enter into energy-related derivatives to hedge exposures to electricity, natural gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the traditional electric operating companies and natural gas distribution utilities have limited exposure to market volatility in energy-related commodity prices. Each of the traditional electric operating companies and certain of the natural gas distribution utilities manage fuel-hedging programs, implemented per the guidelines of their respective state PSCs or other applicable state regulatory agencies, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. The traditional electric operating companies (with respect to wholesale generating capacity) and Southern Power have limited exposure to market volatility in energy-related commodity prices because their long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, the traditional electric operating companies and Southern Power may be exposed to market volatility in energy-related commodity prices to the extent any uncontracted capacity is used to sell electricity.

Southern Company Gas uses storage and transportation capacity contracts to manage market price risks. Southern Company Gas purchases natural gas for storage when the current market price paid to buy and transport natural gas plus the cost to store and finance the natural gas is less than the market price Southern Company Gas will receive in the future, resulting in a positive net adjusted operating margin. Southern Company Gas uses New York Mercantile Exchange (NYMEX) futures and over-the-counter (OTC) contracts to sell natural gas at that future price to substantially protect the adjusted operating margin ultimately realized when the stored natural gas is sold. Southern Company Gas also enters into transactions to secure transportation capacity between delivery points in order to serve its customers and various markets. Southern Company Gas uses NYMEX futures and OTC contracts to capture the price differential between the locations served by the capacity in order to substantially protect the adjusted operating margin ultimately realized when natural gas is physically flowed between the delivery points. These contracts generally meet the definition of derivatives, but are not designated as hedges for accounting purposes.

Southern Company Gas also enters into weather derivative contracts as economic hedges of adjusted operating margins in the event of warmer-than-normal weather. Exchange-traded options are carried at fair value, with changes reflected in operating revenues. Non-exchange-traded options are accounted for using the intrinsic value method. Changes in the intrinsic value for non-exchange-traded contracts are reflected in the statements of income.

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

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the traditional electric operating companies' and natural gas distribution utilities' fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the respective fuel cost recovery clauses.
- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges (which are mainly used to hedge anticipated purchases and sales) are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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

At December 31, 2016 , the net volume of energy-related derivative contracts for natural gas positions totaled 500 million mmBtu for the Southern Company system, with the longest hedge date of 2020 over which the respective entity is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest non-hedge date of 2022 for derivatives not designated as hedges.

In addition to the volumes discussed above, the traditional electric operating companies and Southern Power enter into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 9 million mmBtu.

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to earnings for the next 12-month period ending December 31, 2017 are $17 million for Southern Company.

Interest Rate Derivatives

Southern Company and certain subsidiaries may also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings, with any ineffectiveness recorded directly to earnings. Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value gains or losses are both recorded directly to earnings, providing an offset, with any difference representing ineffectiveness. Fair value gains or losses on derivatives that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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

	Notional Amount	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2016
	(in millions)				*(in millions)*
Cash Flow Hedges of Forecasted Debt					
	$ 80	3-month LIBOR	2.32%	December 2026	$ —
Cash Flow Hedges of Existing Debt					
	900	1-month LIBOR	0.79%	March 2018	3
Fair Value Hedges of Existing Debt					
	250	1.30%	3-month LIBOR + 0.17%	August 2017	—
	250	5.40%	3-month LIBOR + 4.02%	June 2018	—
	500	1.95%	3-month LIBOR + 0.76%	December 2018	(2)
	200	4.25%	3-month LIBOR + 2.46%	December 2019	1
	300	2.75%	3-month LIBOR + 0.92%	June 2020	1
	1,500	2.35%	1-month LIBOR + 0.87%	July 2021	(18)
Derivatives not Designated as Hedges					
	47 (a,b)	3-month LIBOR	2.21%	January 2017 (c)	1
Total	$ 4,027				$ (14)

(a) Swaption at RE Roserock LLC. See Note 12 for additional information.

(b) Amortizing notional amount.

(c) Represents the mandatory settlement date. Settlement amount was based on a 15 -year amortizing swap.

The estimated pre-tax gains (losses) expected to be reclassified from accumulated OCI to interest expense for the next 12 -month period ending December 31, 2017 total $(21) million . Deferred gains and losses are expected to be amortized into earnings through 2046 .

Foreign Currency Derivatives

Southern Company and certain subsidiaries may also enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates, such as that arising from the issuance of debt denominated in a currency other than U.S. dollars. Derivatives related to 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 that the hedged transactions affect earnings, including foreign currency gains or losses arising from changes in the U.S. currency exchange rates. Any ineffectiveness is recorded directly to earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

At December 31, 2016 , the following foreign currency derivatives were outstanding:

	Pay Notional	Pay Rate	Receive Notional	Receive Rate	Hedge Maturity Date	Fair Value Gain (Loss) at December 31, 2016
	(in millions)		*(in millions)*			*(in millions)*
Cash Flow Hedges of Existing Debt						
	$ 677	2.95%	€ 600	1.00%	June 2022	$ (34)
	564	3.78%	500	1.85%	June 2026	(24)
Total	$ 1,241		€ 1,100			$ (58)

The estimated pre-tax gains (losses) that will be reclassified from accumulated OCI to earnings for the next 12 -month period ending December 31, 2017 total $(25) million .

Derivative Financial Statement Presentation and Amounts

Southern Company and its subsidiaries enter into 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. Southern Company and certain subsidiaries also utilize master netting agreements to mitigate exposure to counterparty credit risk. These agreements may contain provisions that permit netting across product lines and against cash collateral.

At December 31, 2016 , fair value amounts of derivative assets and liabilities on the balance sheets are presented net to the extent that there are netting arrangements or similar agreements with the counterparties. At December 31, 2015 , the fair value amounts of derivative instruments were presented gross on the balance sheets.

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

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

	2016		2015	
Derivative Category and Balance Sheet Location	**Assets**	**Liabilities**	Assets	Liabilities
		(in millions)		
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Liabilities from risk management activities, net of collateral	**$ 73**	**$ 27**	$ 3	$ 130
Other deferred charges and assets/Other deferred credits and liabilities	**25**	**33**	—	87
Total derivatives designated as hedging instruments for regulatory purposes	**$ 98**	**$ 60**	$ 3	$ 217
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Energy-related derivatives:				
Other current assets/Liabilities from risk management activities, net of collateral	**$ 23**	**$ 7**	$ 3	$ 2
Interest rate derivatives:				
Other current assets/Liabilities from risk management activities, net of collateral	**12**	**1**	19	23
Other deferred charges and assets/Other deferred credits and liabilities	**1**	**28**	—	7
Foreign currency derivatives:				
Other current assets/Liabilities from risk management activities, net of collateral	**—**	**25**	—	—
Other deferred charges and assets/Other deferred credits and liabilities	**—**	**33**	—	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges	**$ 36**	**$ 94**	$ 22	$ 32
Derivatives not designated as hedging instruments				
Energy-related derivatives:				
Other current assets/Liabilities from risk management activities, net of collateral	**$ 489**	**$ 483**	$ 1	$ 1
Other deferred charges and assets/Other deferred credits and liabilities	**66**	**81**	—	—
Interest rate derivatives:				
Other current assets/Liabilities from risk management activities, net of collateral	**1**	**—**	3	—
Total derivatives not designated as hedging instruments	**$ 556**	**$ 564**	$ 4	$ 1
Gross amounts recognized	**$ 690**	**$ 718**	$ 29	$ 250
Gross amounts offset [(a)]	**$ (462)**	**$ (524)**	$ (15)	$ (15)
Net amounts recognized in the Balance Sheets [(b)]	**$ 228**	**$ 194**	$ 14	$ 235

(a) Gross amounts offset include cash collateral held on deposit in broker margin accounts of $62 million as of December 31, 2016 .
(b) At December 31, 2015 , the fair value amounts for derivative contracts subject to netting arrangements were presented gross on the balance sheet.

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

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

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2016**	2015	**Balance Sheet Location**	**2016**	2015
		(in millions)			*(in millions)*	
Energy-related derivatives: [a]	Other regulatory assets, current	**$ (16)**	$ (130)	Other regulatory liabilities, current	**$ 56**	$ 3
	Other regulatory assets, deferred	**(19)**	(87)	Other regulatory liabilities, deferred	**12**	—
Total energy-related derivative gains (losses) [b]		**$ (35)**	$ (217)		**$ 68**	$ 3

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

(b) Fair value gains and losses recorded in regulatory assets and liabilities include cash collateral held on deposit in broker margin accounts of $8 million as of December 31, 2016 .

For the years ended December 31, 2016 , 2015 , and 2014 , the pre-tax effects of energy-related derivatives, interest rate derivatives, and foreign currency derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Recognized in OCI on Derivative (Effective Portion)**			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**			
	Amount				**Amount**		
Derivative Category	**2016**	2015	2014	**Statements of Income Location**	**2016**	2015	2014
		(in millions)				*(in millions)*	
Energy-related derivatives	**$ 18**	$ —	$ —	Depreciation and amortization	**$ 2**	$ —	$ —
				Cost of natural gas	**(1)**	—	—
Interest rate derivatives	**(180)**	(22)	(16)	Interest expense, net of amounts capitalized	**(18)**	(9)	(8)
Foreign currency derivatives	**(58)**	—	—	Interest expense, net of amounts capitalized	**(13)**	—	—
				Other income (expense), net [*]	**(82)**	—	—
Total	**$ (220)**	$ (22)	$ (16)		**$ (112)**	$ (9)	$ (8)

(*) The reclassification from accumulated OCI into other income (expense), net completely offsets currency gains and losses arising from changes in the U.S. currency exchange rates used to record the euro-denominated notes.

For the years ended December 31, 2016 , 2015 , and 2014 , the pre-tax effects of interest rate derivatives designated as fair value hedging instruments were as follows:

Derivatives in Fair Value Hedging Relationships		**Gain (Loss)**		
Derivative Category	**Statements of Income Location**	**2016**	2015	2014
			(in millions)	
Interest rate derivatives:	Interest expense, net of amounts capitalized	**$ (21)**	$ 2	$ (3)

For all years presented, the pre-tax effects of interest rate derivatives designated as fair value hedging instruments were offset by changes to the carrying value of long-term debt.

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

For the years ended December 31, 2016 , 2015 , and 2014 , the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income were as follows:

Derivatives Not Designated as Hedging Instruments		Unrealized Gain (Loss) Recognized in Income		
		Amount		
Derivative Category	**Statements of Income Location**	**2016**	2015	2014
			(in millions)	
Energy-related derivatives	Wholesale electric revenues	**$ 2**	$ (5)	$ 6
	Fuel	**—**	3	(4)
	Natural gas revenues (*)	**33**	—	—
	Cost of natural gas	**3**	—	—
Total		**$ 38**	$ (2)	$ 2

(*) Excludes gains (losses) recorded in cost of natural gas associated with weather derivatives of $6 million for the period ended December 31, 2016 .

For the years ended December 31, 2016 , 2015 , and 2014 , the pre-tax effects of interest rate derivatives not designated as hedging instruments were immaterial.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain Southern Company subsidiaries. At December 31, 2016 , the fair value of derivative liabilities with contingent features was immaterial. The maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were immaterial and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

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

Southern Company maintains accounts with brokers or the clearing houses of certain exchanges to facilitate financial derivative transactions. Based on the value of the positions in these accounts and the associated margin requirements, Southern Company may be required to deposit cash into these accounts. At December 31, 2016 , cash collateral held on deposit in broker margin accounts was $62 million .

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

12. ACQUISITIONS

Southern Company

Merger with Southern Company Gas

Southern Company Gas is an energy services holding company whose primary business is the distribution of natural gas through the natural gas distribution utilities. On July 1, 2016, Southern Company completed the Merger for a total purchase price of approximately $8.0 billion and Southern Company Gas became a wholly-owned, direct subsidiary of Southern Company.

The Merger was accounted for using the acquisition method of accounting with the assets acquired and liabilities assumed recognized at fair value as of the acquisition date. The following table presents the purchase price allocation:

Southern Company Gas Purchase Price	December 31, 2016	
	(in millions)	
Current assets	$	1,557
Property, plant, and equipment		10,108
Goodwill		5,967
Intangible assets		400
Regulatory assets		1,118
Other assets		229
Current liabilities		(2,201)
Other liabilities		(4,742)
Long-term debt		(4,261)
Noncontrolling interests		(174)
Total purchase price	$	8,001

The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed of $6.0 billion is recognized as goodwill, which is primarily attributable to positioning the Southern Company system to provide natural gas infrastructure to meet customers' growing energy needs and to compete for growth across the energy value chain. Southern Company anticipates that much of the value assigned to goodwill will not be deductible for tax purposes.

The valuation of identifiable intangible assets included customer relationships, trade names, and storage and transportation contracts with estimated lives of one to 28 years . The estimated fair value measurements of identifiable intangible assets were primarily based on significant unobservable inputs (Level 3).

The results of operations for Southern Company Gas have been included in the consolidated financial statements from the date of acquisition and consist of operating revenues of $1.7 billion and net income of $114 million .

The following summarized unaudited pro forma consolidated statement of earnings information assumes that the acquisition of Southern Company Gas was completed on January 1, 2015. The summarized unaudited pro forma consolidated statement of earnings information includes adjustments for (i) intercompany sales, (ii) amortization of intangible assets, (iii) adjustments to interest expense to reflect current interest rates on Southern Company Gas debt and additional interest expense associated with borrowings by Southern Company to fund the Merger, and (iv) the elimination of nonrecurring expenses associated with the Merger.

	2016		2015	
Operating revenues (in millions)	$	21,791	$	21,430
Net income attributable to Southern Company (in millions)	$	2,591	$	2,665
Basic EPS	$	2.70	$	2.85
Diluted EPS	$	2.68	$	2.84

These unaudited pro forma results are for comparative purposes only and may not be indicative of the results that would have occurred had this acquisition been completed on January 1, 2015 or the results that would be attained in the future.

During 2016 and 2015, Southern Company recorded in its statements of income costs associated with the Merger of approximately $111 million and $41 million , respectively, of which $80 million and $27 million is included in operating expenses and $31 million and $14 million is included in other income and (expense), respectively. These costs include external transaction costs for financing, legal, and consulting services, as well as customer rate credits and additional compensation-related expenses.

Acquisition of PowerSecure

On May 9, 2016, Southern Company acquired all of the outstanding stock of PowerSecure, a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure, for $18.75 per common share in cash, resulting in an aggregate purchase price of $429 million . As a result, PowerSecure became a wholly-owned subsidiary of Southern Company.

The acquisition of PowerSecure was accounted for using the acquisition method of accounting with the assets acquired and liabilities assumed recognized at fair value as of the acquisition date. The allocation of the purchase price is as follows:

PowerSecure Purchase Price		December 31, 2016
		(in millions)
Current assets	$	172
Property, plant, and equipment		46
Intangible assets		101
Goodwill		282
Other assets		4
Current liabilities		(114)
Long-term debt, including current portion		(48)
Deferred credits and other liabilities		(14)
Total purchase price	$	429

The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed of $282 million was recognized as goodwill, which is primarily attributable to expected business expansion opportunities for PowerSecure. Southern Company anticipates that the majority of the value assigned to goodwill will not be deductible for tax purposes.

The valuation of identifiable intangible assets included customer relationships, trade names, patents, backlog, and software with estimated lives of one to 26 years . The estimated fair value measurements of identifiable intangible assets were primarily based on significant unobservable inputs (Level 3).

The results of operations for PowerSecure have been included in the consolidated financial statements from the date of acquisition and are immaterial to the consolidated financial results of Southern Company. Pro forma results of operations have not been presented for the acquisition because the effects of the acquisition were immaterial to Southern Company's consolidated financial results for all periods presented.

Alliance with Bloom Energy Corporation

On October 24, 2016, a subsidiary of Southern Company acquired from an affiliate of Bloom Energy Corporation (Bloom) all of the equity interests of 2016 ESA HoldCo, LLC and its subsidiary, 2016 ESA Project Company, LLC. 2016 ESA Project Company, LLC expects to acquire 50 MWs of Bloom fuel cell systems to serve commercial and industrial customers under long-term PPAs. In connection with this transaction, PowerSecure and Bloom agreed to pursue a strategic alliance to develop technology for behind-the-meter energy solutions.

Investment in Southern Natural Gas

On July 10, 2016, Southern Company and Kinder Morgan, Inc. entered into a definitive agreement for Southern Company to acquire a 50% equity interest in SNG, which is the owner of a 7,000 -mile pipeline system connecting natural gas supply basins in Texas, Louisiana, Mississippi, and Alabama to markets in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina, and Tennessee. On August 31, 2016, Southern Company assigned its rights and obligations under the definitive agreement to a wholly-owned, indirect subsidiary of Southern Company Gas. On September 1, 2016, Southern Company Gas completed the acquisition for a purchase price of approximately $1.4 billion . The investment in SNG is accounted for using the equity method.

Acquisition of Remaining Interest in SouthStar

SouthStar is a retail natural gas marketer and markets natural gas to residential, commercial, and industrial customers, primarily in Georgia and Illinois. Southern Company Gas previously had an 85% ownership interest in SouthStar, with Piedmont owning the remaining 15% . In October 2016, Southern Company Gas purchased Piedmont's 15% interest in SouthStar for $160 million .

Southern Power

During 2016 and 2015 , in accordance with its overall growth strategy, Southern Power or one of its wholly-owned subsidiaries, Southern Renewable Partnerships, LLC (SRP) or Southern Renewable Energy, Inc. (SRE), acquired or contracted to acquire the projects discussed below. Also, on March 29, 2016, Southern Power acquired an additional 15% interest in Desert Stateline, 51% of which was initially acquired in August 2015. As a result, Southern Power and the class B member are now entitled to 66% and

34% , respectively, of all cash distributions from Desert Stateline. In addition, Southern Power will continue to be entitled to substantially all of the federal tax benefits with respect to the transaction.

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

The following table presents Southern Power's acquisitions during and subsequent to the year ended December 31, 2016 .

Project Facility	Resource	Seller; Acquisition Date	Approximate Nameplate Capacity (MW)	Location	Southern Power Percentage Ownership	Actual/Expected COD	PPA Contract Period
Acquisitions During the Year Ended December 31, 2016							
Boulder 1	Solar	SunPower Corp. November 16, 2016	100	Clark County, NV	51% [(a)]	December 2016	20 years
Calipatria	Solar	Solar Frontier Americas Holding LLC February 11, 2016	20	Imperial County, CA	90% [(b)]	February 2016	20 years
East Pecos	Solar	First Solar, Inc. March 4, 2016	120	Pecos County, TX	100%	March 2017	15 years
Grant Plains	Wind	Apex Clean Energy Holdings, LLC August 26, 2016	147	Grant County, OK	100%	December 2016	20 years and 12 years [(c)]
Grant Wind	Wind	Apex Clean Energy Holdings, LLC April 7, 2016	151	Grant County, OK	100%	April 2016	20 years
Henrietta	Solar	SunPower Corp. July 1, 2016	102	Kings County, CA	51% [(a)]	July 2016	20 years
Lamesa	Solar	RES America Developments Inc. July 1, 2016	102	Dawson County, TX	100%	Second quarter 2017	15 years
Mankato [(d)]	Natural Gas	Calpine Corporation October 26, 2016	375	Mankato, MN	100%	N/A [(e)]	10 years
Passadumkeag	Wind	Quantum Utility Generation, LLC June 30, 2016	42	Penobscot County, ME	100%	July 2016	15 years
Rutherford	Solar	Cypress Creek Renewables, LLC July 1, 2016	74	Rutherford County, NC	90% [(b)]	December 2016	15 years
Salt Fork	Wind	EDF Renewable Energy, Inc. December 1, 2016	174	Donley and Gray Counties, TX	100%	December 2016	14 years and 12 years
Tyler Bluff	Wind	EDF Renewable Energy, Inc. December 21, 2016	125	Cooke County, TX	100%	December 2016	12 years
Wake Wind	Wind	Invenergy Wind Global LLC October 26, 2016	257	Floyd and Crosby Counties, TX	90.1% [(f)]	October 2016	12 years
Acquisitions Subsequent to December 31, 2016							
Bethel	Wind	Invenergy Wind Global LLC January 6, 2017	276	Castro County, TX	100%	January 2017	12 years

(a) Southern Power owns 100% of the class A membership interests and a wholly-owned subsidiary of the seller owns 100% of the class B membership interests. Southern Power and the class B member are entitled to 51% and 49% , respectively, of all cash distributions from the project. In addition, Southern Power is entitled to substantially all of the federal tax benefits with respect to the transaction.
(b) Southern Power owns 90% , with the minority owner, Turner Renewable Energy, LLC (TRE), owning 10% .
(c) In addition to the 20 -year and 12 -year PPAs, the facility has a 10 -year contract with Allianz Risk Transfer (Bermuda) Ltd.
(d) Under the terms of the remaining 10 -year PPA and the 20 -year expansion PPA, approximately $408 million of assets, primarily related to property, plant, and equipment, are subject to lien at December 31, 2016.
(e) The acquisition included a fully operational 375 -MW natural gas-fired combined-cycle facility.
(f) Southern Power owns 90.1% , with the minority owner, Invenergy Wind Global LLC, owning 9.9% .

Acquisitions During the Year Ended December 31, 2016

Southern Power's aggregate purchase price for acquisitions during the year ended December 31, 2016 was approximately $2.3 billion . Including the minority owner TRE's 10% ownership interest in Calipatria and Rutherford, SunPower Corp's 49% ownership interest in Boulder 1 and Henrietta, along with the assumption of $217 million in construction debt (non-recourse to Southern Power), and Invenergy Wind Global LLC's 9.9% ownership interest in Wake Wind, the total aggregate purchase price is approximately $2.6 billion for the project facilities acquired during the year ended December 31, 2016 . The allocations of the purchase price to individual assets have not been finalized, except for Calipatria, East Pecos, Lamesa, and Rutherford, which were finalized with no changes to amounts originally reported. The fair values of the assets and liabilities acquired through the business combinations were recorded as follows:

	2016
	(in millions)
CWIP	$ 2,354
Property, plant, and equipment	302
Intangible assets [(a)]	128
Other assets	52
Accounts payable	(16)
Debt	(217)
Total purchase price	$ 2,603
Funded by:	
Southern Power [(b)(c)]	$ 2,345
Noncontrolling interests [(d)(e)]	258
Total purchase price	$ 2,603

(a) Intangible assets consist of acquired PPAs that will be amortized over 10 and 20 -year terms. The estimated amortization for future periods is approximately $9 million per year.
(b) At December 31, 2016 , $461 million is included in acquisitions payable on the balance sheets.
(c) Includes approximately $281 million of contingent consideration, of which $67 million remains payable at December 31, 2016.
(d) Includes approximately $51 million of non-cash contributions recorded as capital contributions from noncontrolling interests in the statements of stockholders' equity.
(e) Includes approximately $142 million of contingent consideration, all of which had been paid at December 31, 2016 by the noncontrolling interests.

The following table presents Southern Power's acquisitions for the year ended December 31, 2015 . During the year ended December 31, 2016 , the fair values of assets and liabilities acquired for all projects listed below were finalized with no changes to amounts originally reported.

Project Facility	Resource	Seller; Acquisition Date	Approximate Nameplate Capacity (*MW*)	Location	Southern Power Percentage Ownership	Actual COD	PPA Contract Period
Acquisitions for the Year Ended December 31, 2015							
Desert Stateline	Solar	First Solar Inc. August 31, 2015	299 [(a)]	San Bernardino County, CA	51% [(b)]	From December 2015 to July 2016	20 years
Garland and Garland A	Solar	Recurrent Energy, LLC December 17, 2015	205	Kern County, CA	51% [(b)]	October and August 2016	15 years and 20 years
Kay Wind	Wind	Apex Clean Energy Holdings, LLC December 11, 2015	299	Kay County, OK	100%	December 2015	20 years
Lost Hills Blackwell	Solar	First Solar Inc. April 15, 2015	33	Kern County, CA	51% [(b)]	April 2015	29 years
Morelos	Solar	Solar Frontier Americas Holding, LLC October 22, 2015	15	Kern County, CA	90% [(c)]	November 2015	20 years
North Star	Solar	First Solar Inc. April 30, 2015	61	Fresno County, CA	51% [(b)]	June 2015	20 years
Roserock	Solar	Recurrent Energy, LLC November 23, 2015	160	Pecos County, TX	51% [(b)]	November 2016	20 years
Tranquillity	Solar	Recurrent Energy, LLC August 28, 2015	205	Fresno County, CA	51% [(b)]	July 2016	18 years

(a) The facility has a total of 299 MWs, of which 110 MWs were placed in service in the fourth quarter 2015 and the remainder by July 2016.

(b) Southern Power owns 100% of the class A membership interests and a wholly-owned subsidiary of the seller owns 100% of the class B membership interests. Southern Power and the class B member are entitled to 51% and 49% , respectively, of all cash distributions from the project. In addition, Southern Power is entitled to substantially all of the federal tax benefits with respect to the transaction.

(c) Southern Power owns 90% , with the minority owner, TRE, owning 10% .

Acquisitions During the Year Ended December 31, 2015

Southern Power's aggregate purchase price for the project facilities acquired during the year ended December 31, 2015 was approximately $1.4 billion . Including the minority owner TRE's 10% ownership interest in Morelos, First Solar Inc.'s 49% ownership interest in Desert Stateline, Lost Hills Blackwell, and North Star, and Recurrent Energy, LLC's 49% ownership interest in Garland, Garland A, Roserock, and Tranquillity, the total aggregate purchase price was approximately $1.9 billion for the project facilities acquired during the year ended December 31, 2015.

The fair values of the assets and liabilities acquired through the business combinations were recorded as follows:

		2015
		(in millions)
CWIP	$	1,367
Property, plant, and equipment		315
Intangible assets [(a)]		274
Other assets		64
Accounts payable		(89)
Total purchase price	$	1,931
Funded by:		
Southern Power [(b)]	$	1,440
Noncontrolling interests [(c)] [(d)]		491
Total purchase price	$	1,931

(a) Intangible assets consist of acquired PPAs that will be amortized over 20 -year terms. The estimated amortization for future periods is approximately $14 million per year.
(b) Includes approximately $195 million of contingent consideration, all of which has been paid at December 31, 2016 .
(c) Includes approximately $227 million of non-cash contributions recorded as capital contributions from noncontrolling interests in the statements of stockholders' equity.
(d) Includes approximately $76 million of contingent consideration, all of which had been paid at December 31, 2016 by the noncontrolling interests.

Construction Projects

Construction Projects Completed

During 2016, in accordance with Southern Power's overall growth strategy, Southern Power completed construction of, and placed in service, the projects set forth in the table below. Total costs of construction incurred for these projects were $3.2 billion .

Solar Facility	Seller	Approximate Nameplate Capacity (*MW*)	Location	Actual COD	PPA Contract Period
Butler	CERSM, LLC and Community Energy, Inc.	103	Taylor County, GA	December 2016	30 years [(a)]
Butler Solar Farm	Strata Solar Development, LLC	22	Taylor County, GA	February 2016	20 years [(a)]
Desert Stateline	First Solar Development, LLC	299 [(b)]	San Bernardino County, CA	From December 2015 to July 2016	20 years
Garland	Recurrent Energy, LLC	185	Kern County, CA	October 2016	15 years
Garland A	Recurrent Energy, LLC	20	Kern County, CA	August 2016	20 years
Pawpaw	Longview Solar, LLC	30	Taylor County, GA	March 2016	30 years
Roserock [(c)]	Recurrent Energy, LLC	160	Pecos County, TX	November 2016	20 years
Sandhills	N/A	146	Taylor County, GA	October 2016	25 years
Tranquillity	Recurrent Energy, LLC	205	Fresno County, CA	July 2016	18 years

(a) Affiliate PPA approved by the FERC.
(b) The facility has a total of 299 MWs, of which 110 MWs were placed in service in the fourth quarter 2015 and the remainder by July 2016.
(c) Prior to placing the Roserock facility in service, certain solar panels were damaged. While the facility is currently generating energy as expected, Southern Power is pursuing remedies under its insurance policies and other contracts to repair or replace these solar panels.

Construction Projects in Progress

At December 31, 2016 , Southern Power continued construction of the East Pecos and Lamesa solar facilities that were acquired in 2016 . In addition, as part of Southern Power's acquisition of Mankato in 2016, Southern Power commenced construction of an additional 345 -MW expansion, which is fully contracted under a new 20 -year PPA. Total aggregate construction costs, excluding the acquisition costs, are expected to be $530 million to $590 million for East Pecos, Lamesa, and Mankato. At December 31,

2016, the construction costs totaled $386 million and are included in CWIP. The ultimate outcome of these matters cannot be determined at this time.

The following table presents Southern Power's construction projects in progress as of December 31, 2016:

Project Facility	Resource	Approximate Nameplate Capacity (MW)	Location	Actual/Expected COD	PPA Contract Period
East Pecos	Solar	120	Pecos County, TX	March 2017	15 years
Lamesa	Solar	102	Dawson County, TX	Second quarter 2017	15 years
Mankato	Natural Gas	345	Mankato, MN	Second quarter 2019	20 years

Development Projects

In December 2016, as part of Southern Power's renewable development strategy, SRP entered into a joint development agreement with Renewable Energy Systems Americas, Inc. to develop and construct approximately 3,000 MWs across 10 wind projects expected to be placed in service between 2018 and 2020. Also in December 2016, Southern Power signed agreements and made payments to purchase wind turbine equipment from Siemens Wind Power, Inc. and Vestas-American Wind Technology, Inc. to be used for construction of the facilities. Once these wind projects reach commercial operations, they are expected to qualify for 100% PTCs. The ultimate outcome of these matters cannot be determined at this time.

13. SEGMENT AND RELATED INFORMATION

The primary business of the Southern Company system is electricity sales by the traditional electric operating companies and Southern Power and, as a result of closing the Merger, the distribution of natural gas by Southern Company Gas. The four traditional electric operating companies – Alabama Power, Georgia Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages 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 the natural gas distribution utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations.

Southern Company's reportable business segments are the sale of electricity by the four traditional electric operating companies, the sale of electricity in the competitive wholesale market by Southern Power, and the sale of natural gas and other complementary products and services by Southern Company Gas. Revenues from sales by Southern Power to the traditional electric operating companies were $419 million , $417 million , and $383 million in 2016 , 2015 , and 2014 , respectively. The "All Other" column includes the Southern Company parent entity, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include providing energy technologies and services to electric utilities and large industrial, commercial, institutional, and municipal customers; as well as investments in telecommunications and leveraged lease projects. All other inter-segment revenues are not material. Financial data for business segments and products and services for the years ended December 31, 2016 , 2015 , and 2014 was as follows:

NOTES (continued)
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	Electric Utilities							
	Traditional Electric Operating Companies	Southern Power	Eliminations	Total	Southern Company Gas	All Other	Eliminations	Consolidated
				(in millions)				
2016								
Operating revenues	**$ 16,803**	**$ 1,577**	**$ (439)**	**$ 17,941**	**$ 1,652**	**$ 463**	**$ (160)**	**$ 19,896**
Depreciation and amortization	**1,881**	**352**	**—**	**2,233**	**238**	**31**	**—**	**2,502**
Interest income	**6**	**7**	**—**	**13**	**2**	**20**	**(15)**	**20**
Earnings from equity method investments	**2**	**—**	**—**	**2**	**60**	**(3)**	**—**	**59**
Interest expense	**814**	**117**	**—**	**931**	**81**	**317**	**(12)**	**1,317**
Income taxes	**1,286**	**(195)**	**—**	**1,091**	**76**	**(216)**	**—**	**951**
Segment net income (loss) [a] [b]	**2,233**	**338**	**—**	**2,571**	**114**	**(230)**	**(7)**	**2,448**
Total assets	**72,141**	**15,169**	**(316)**	**86,994**	**21,853**	**2,474**	**(1,624)**	**109,697**
Gross property additions	**4,852**	**2,114**	**—**	**6,966**	**618**	**41**	**(1)**	**7,624**
2015								
Operating revenues	$ 16,491	$ 1,390	$ (439)	$ 17,442	$ —	$ 152	$ (105)	$ 17,489
Depreciation and amortization	1,772	248	—	2,020	—	14	—	2,034
Interest income	19	2	1	22	—	6	(5)	23
Earnings from equity method investments	1	—	—	1	—	(1)	—	—
Interest expense	697	77	—	774	—	69	(3)	840
Income taxes	1,305	21	—	1,326	—	(132)	—	1,194
Segment net income (loss) [a] [b]	2,186	215	—	2,401	—	(32)	(2)	2,367
Total assets	69,052	8,905	(397)	77,560	—	1,819	(1,061)	78,318
Gross property additions	5,124	1,005	—	6,129	—	40	—	6,169
2014								
Operating revenues	$ 17,354	$ 1,501	$ (449)	$ 18,406	$ —	$ 159	$ (98)	$ 18,467
Depreciation and amortization	1,709	220	—	1,929	—	16	—	1,945
Interest income	17	1	—	18	—	3	(2)	19
Earnings from equity method investments	1	—	—	1	—	(1)	—	—
Interest expense	705	89	—	794	—	43	(2)	835
Income taxes	1,056	(3)	—	1,053	—	(76)	—	977
Segment net income (loss) [a] [b]	1,797	172	—	1,969	—	(3)	(3)	1,963
Total assets [c]	64,300	5,233	(131)	69,402	—	1,143	(312)	70,233
Gross property additions	5,568	942	—	6,510	—	11	1	6,522

(a) Attributable to Southern Company.

(b) Segment net income (loss) for the traditional electric operating companies includes pre-tax charges for estimated probable losses on the Kemper IGCC of $428 million ($264 million after tax) in 2016, $365 million ($226 million after tax) in 2015, and $868 million ($536 million after tax) in 2014. See Note 3 under " Integrated Coal Gasification Combined Cycle – Kemper IGCC Schedule and Cost Estimate " for additional information.

(c) Net of $202 million of unamortized debt issuance costs as of December 31, 2014. Also net of $488 million of deferred tax assets as of December 31, 2014.

Products and Services

Electric Utilities' Revenues

Year	Retail	Wholesale	Other	Total
			(in millions)	
2016	**$ 15,234**	**$ 1,926**	**$ 781**	**$ 17,941**
2015	14,987	1,798	657	17,442
2014	15,550	2,184	672	18,406

Southern Company Gas' Revenues

Year	Gas Distribution Operations	Gas Marketing Services	All Other	Total
			(in millions)	
2016	**$ 1,266**	**$ 354**	**$ 32**	**$ 1,652**

14. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

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

				Per Common Share				
							Trading Price Range	
Quarter Ended	Operating Revenues	Operating Income	Consolidated Net Income Attributable to Southern Company	Basic Earnings	Diluted Earnings	Dividends	High	Low
		(in millions)						
March 2016	**$ 3,992**	**$ 940**	**$ 489**	**$ 0.53**	**$ 0.53**	**$ 0.5425**	**$ 51.73**	**$ 46.00**
June 2016	**4,459**	**1,185**	**623**	**0.67**	**0.66**	**0.5600**	**53.64**	**47.62**
September 2016	**6,264**	**1,917**	**1,139**	**1.18**	**1.17**	**0.5600**	**54.64**	**50.00**
December 2016	**5,181**	**587**	**197**	**0.20**	**0.20**	**0.5600**	**52.23**	**46.20**
March 2015	$ 4,183	$ 957	$ 508	$ 0.56	$ 0.56	$ 0.5250	$ 53.16	$ 43.55
June 2015	4,337	1,098	629	0.69	0.69	0.5425	45.44	41.40
September 2015	5,401	1,649	959	1.05	1.05	0.5425	46.84	41.81
December 2015	3,568	578	271	0.30	0.30	0.5425	47.50	43.38

In accordance with the adoption of ASU 2016-09 (see Note 1 under "Recently Issued Accounting Standards"), previously reported amounts for income tax expense were reduced by $9 million in the third quarter 2016, $11 million in the second quarter 2016, and $5 million in the first quarter 2016. In addition, basic and diluted EPS increased from previously reported amounts of $1.17 and $1.16 in the third quarter 2016, respectively, $0.65 and $0.65 in the second quarter 2016, respectively, and $0.53 and $0.53 in the first quarter 2016, respectively.

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

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

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA
For the Periods Ended December 2012 through 2016
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	2016 (a)	2015	2014	2013	2012
Operating Revenues (in millions)	**$ 19,896**	$ 17,489	$ 18,467	$ 17,087	$ 16,537
Total Assets (in millions) (b)(c)	**$ 109,697**	$ 78,318	$ 70,233	$ 64,264	$ 62,814
Gross Property Additions (in millions)	**$ 7,624**	$ 6,169	$ 6,522	$ 5,868	$ 5,059
Return on Average Common Equity (percent)	**10.80**	11.68	10.08	8.82	13.10
Cash Dividends Paid Per Share of Common Stock	**$ 2.2225**	$ 2.1525	$ 2.0825	$ 2.0125	$ 1.9425
Consolidated Net Income Attributable to Southern Company (in millions)	**$ 2,448**	$ 2,367	$ 1,963	$ 1,644	$ 2,350
Earnings Per Share —					
Basic	**$ 2.57**	$ 2.60	$ 2.19	$ 1.88	$ 2.70
Diluted	**2.55**	2.59	2.18	1.87	2.67
Capitalization (in millions):					
Common stock equity	**$ 24,758**	$ 20,592	$ 19,949	$ 19,008	$ 18,297
Preferred and preference stock of subsidiaries and noncontrolling interests	**1,854**	1,390	977	756	707
Redeemable preferred stock of subsidiaries	**118**	118	375	375	375
Redeemable noncontrolling interests	**164**	43	39	—	—
Long-term debt (b)	**42,629**	24,688	20,644	21,205	19,143
Total (excluding amounts due within one year)	**$ 69,523**	$ 46,831	$ 41,984	$ 41,344	$ 38,522
Capitalization Ratios (percent):					
Common stock equity	**35.6**	44.0	47.5	46.0	47.5
Preferred and preference stock of subsidiaries and noncontrolling interests	**2.7**	3.0	2.3	1.8	1.8
Redeemable preferred stock of subsidiaries	**0.2**	0.3	0.9	0.9	1.0
Redeemable noncontrolling interests	**0.2**	0.1	0.1	—	—
Long-term debt (b)	**61.3**	52.6	49.2	51.3	49.7
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Other Common Stock Data:					
Book value per share	**$ 25.00**	$ 22.59	$ 21.98	$ 21.43	$ 21.09
Market price per share:					
High	**$ 54.64**	$ 53.16	$ 51.28	$ 48.74	$ 48.59
Low	**46.00**	41.40	40.27	40.03	41.75
Close (year-end)	**49.19**	46.79	49.11	41.11	42.81
Market-to-book ratio (year-end) (percent)	**196.8**	207.2	223.4	191.8	203.0
Price-earnings ratio (year-end) (times)	**19.1**	18.0	22.4	21.9	15.9
Dividends paid (in millions)	**$ 2,104**	$ 1,959	$ 1,866	$ 1,762	$ 1,693
Dividend yield (year-end) (percent)	**4.5**	4.6	4.2	4.9	4.5
Dividend payout ratio (percent)	**86.0**	82.7	95.0	107.1	72.0
Shares outstanding (in thousands):					
Average	**951,332**	910,024	897,194	876,755	871,388
Year-end	**990,394**	911,721	907,777	887,086	867,768
Stockholders of record (year-end)	**126,338**	131,771	137,369	143,800	149,628

(a) The 2016 selected financial and operating data includes the operations of Southern Company Gas from the date of the Merger, July 1, 2016, through December 31, 2016. See Note 12 under "Merger with Southern Company Gas" for additional information.

(b) A reclassification of debt issuance costs from Total Assets to Long-term debt of $202 million, $139 million, and $133 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(c) A reclassification of deferred tax assets from Total Assets of $488 million, $143 million, and $202 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA (continued)
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	2016 [(a)]	2015	2014	2013	2012
Operating Revenues (in millions):					
Residential	**$ 6,614**	$ 6,383	$ 6,499	$ 6,011	$ 5,891
Commercial	**5,394**	5,317	5,469	5,214	5,097
Industrial	**3,171**	3,172	3,449	3,188	3,071
Other	**55**	115	133	128	128
Total retail	**15,234**	14,987	15,550	14,541	14,187
Wholesale	**1,926**	1,798	2,184	1,855	1,675
Total revenues from sales of electricity	**17,160**	16,785	17,734	16,396	15,862
Natural gas revenues	**1,596**	—	—	—	—
Other revenues	**1,140**	704	733	691	675
Total	**$ 19,896**	$ 17,489	$ 18,467	$ 17,087	$ 16,537
Kilowatt-Hour Sales (in millions):					
Residential	**53,337**	52,121	53,347	50,575	50,454
Commercial	**53,733**	53,525	53,243	52,551	53,007
Industrial	**52,792**	53,941	54,140	52,429	51,674
Other	**883**	897	909	902	919
Total retail	**160,745**	160,484	161,639	156,457	156,054
Wholesale sales	**34,896**	30,505	32,786	26,944	27,563
Total	**195,641**	190,989	194,425	183,401	183,617
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**12.40**	12.25	12.18	11.89	11.68
Commercial	**10.04**	9.93	10.27	9.92	9.62
Industrial	**6.01**	5.88	6.37	6.08	5.94
Total retail	**9.48**	9.34	9.62	9.29	9.09
Wholesale	**5.52**	5.89	6.66	6.88	6.08
Total sales	**8.77**	8.79	9.12	8.94	8.64
Average Annual Kilowatt-Hour					
Use Per Residential Customer	**12,387**	13,318	13,765	13,144	13,187
Average Annual Revenue					
Per Residential Customer	**$ 1,541**	$ 1,630	$ 1,679	$ 1,562	$ 1,540
Plant Nameplate Capacity					
Ratings (year-end) (megawatts)	**46,291**	44,223	46,549	45,502	45,740
Maximum Peak-Hour Demand (megawatts):					
Winter	**32,272**	36,794	37,234	27,555	31,705
Summer	**35,781**	36,195	35,396	33,557	35,479
System Reserve Margin (at peak) (percent) [(b)]	**34.2**	33.2	19.8	21.5	20.8
Annual Load Factor (percent)	**61.5**	59.9	59.6	63.2	59.5
Plant Availability (percent):					
Fossil-steam	**86.4**	86.1	85.8	87.7	89.4
Nuclear	**93.3**	93.5	91.5	91.5	94.2

(a) The 2016 selected financial and operating data includes the operations of Southern Company Gas from the date of the Merger, July 1, 2016, through December 31, 2016. See Note 12 under "Merger with Southern Company Gas" for additional information.

(b) Beginning in 2014, system reserve margin is calculated to include unrecognized capacity.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA (continued)
For the Periods Ended December 2012 through 2016
Southern Company and Subsidiary Companies 2016 Annual Report

	2016 [(a)]	2015	2014	2013	2012
Source of Energy Supply (percent):					
Coal	**30.6**	32.3	39.3	36.9	35.2
Nuclear	**14.7**	15.2	14.8	15.5	16.2
Oil and gas	**42.2**	42.7	37.0	37.2	38.2
Hydro	**2.1**	2.6	2.5	3.9	1.7
Other renewables	**2.4**	0.8	0.4	0.1	0.1
Purchased power	**8.0**	6.4	6.0	6.4	8.6
Total	**100.0**	100.0	100.0	100.0	100.0
Gas Sales Volumes (mmBtu in millions):					
Firm	**296**	—	—	—	—
Interruptible	**53**	—	—	—	—
Total	**349**	—	—	—	—
Traditional Electric Operating Company Customers (year-end) (in thousands):					
Residential	**3,970**	3,928	3,890	3,859	3,832
Commercial [(b)]	**595**	590	586	582	579
Industrial [(b)]	**17**	17	17	17	17
Other	**11**	11	11	9	8
Total electric customers	**4,593**	4,546	4,504	4,467	4,436
Gas distribution operations customers	**4,586**	—	—	—	—
Total utility customers	**9,179**	4,546	4,504	4,467	4,436
Employees (year-end)	**32,020**	26,703	26,369	26,300	26,439

(a) The 2016 selected financial and operating data includes the operations of Southern Company Gas from the date of the Merger, July 1, 2016, through December 31, 2016. See Note 12 under "Merger with Southern Company Gas" for additional information.

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

ALABAMA POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Alabama Power Company 2016 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, 2016 .

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

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

February 21, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Alabama Power Company

We have audited the accompanying balance sheets and statements of capitalization of Alabama Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2016 and 2015 , and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2016 . These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such financial statements (pages II-182 to II-226) present fairly, in all material respects, the financial position of Alabama Power Company as of December 31, 2016 and 2015 , and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016 , in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Birmingham, Alabama
February 21, 2017

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
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
Southern Company	The Southern Company
Southern Company Gas	Southern Company Gas (formerly known as AGL Resources Inc.) 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
traditional electric operating companies	Alabama Power Company, Georgia Power, Gulf Power, and Mississippi Power

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

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 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 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 an expected Rate RSE refund, a decrease in AFUDC equity, and an increase in depreciation. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate RSE" herein for additional information.

The Company's 2015 net income after dividends on preferred and preference stock was $785 million , representing a $24 million, or 3.2%, increase over the previous year. The increase was due primarily to an increase in rates under Rate RSE effective January 1, 2015. This increase was partially offset by a decrease in weather-related revenues resulting from milder weather experienced in 2015 as compared to 2014 and an increase in amortization.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2016 Annual Report

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2016	2016	2015
		(in millions)	
Operating revenues	$ 5,889	$ 121	$ (174)
Fuel	1,297	(45)	(263)
Purchased power	334	(17)	(34)
Other operations and maintenance	1,510	9	33
Depreciation and amortization	703	60	40
Taxes other than income taxes	380	12	12
Total operating expenses	4,224	19	(212)
Operating income	1,665	102	38
Allowance for equity funds used during construction	28	(32)	11
Interest income	16	1	—
Interest expense, net of amounts capitalized	302	28	19
Other income (expense), net	(37)	10	(25)
Income taxes	531	25	(6)
Net income	839	28	11
Dividends on preferred and preference stock	17	(9)	(13)
Net income after dividends on preferred and preference stock	$ 822	$ 37	$ 24

Operating Revenues

Operating revenues for 2016 were $5.9 billion , reflecting a $121 million increase from 2015. Details of operating revenues were as follows:

	Amount	
	2016	2015
	(in millions)	
Retail — prior year	$ 5,234	$ 5,249
Estimated change resulting from —		
Rates and pricing	147	204
Sales decline	(20)	(11)
Weather	31	(43)
Fuel and other cost recovery	(70)	(165)
Retail — current year	5,322	5,234
Wholesale revenues —		
Non-affiliates	283	241
Affiliates	69	84
Total wholesale revenues	352	325
Other operating revenues	215	209
Total operating revenues	$ 5,889	$ 5,768
Percent change	2.1%	(2.9)%

Retail revenues in 2016 were $5.3 billion . These revenues increased $ 88 million , or 1.7% , in 2016 and decreased $15 million, or 0.3%, in 2015, each as compared to the prior year. 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 an expected Rate RSE refund. The decrease in 2015 was due to a decrease in fuel revenues and milder weather in 2015 as compared to 2014, partially offset by an increase in revenues due to a Rate RSE increase effective January 1, 2015. 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 growth and weather.

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

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

	2016	2015	2014
		(in millions)	
Capacity and other	**$ 154**	$ 140	$ 154
Energy	**129**	101	127
Total non-affiliated	**$ 283**	$ 241	$ 281

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 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 wholesale contract in the first quarter 2016 partially offset by a 12.1% decrease in the price of energy due to lower natural gas prices. In 2015, wholesale revenues from sales to non-affiliates decreased $40 million, or 14.2%, as compared to the prior year. This decrease reflects a $26 million decrease in revenues from energy sales and a $14 million decrease in capacity revenues. In 2015, KWH sales decreased 6.3% primarily due to the market availability of lower cost natural gas resources and an 8.4% decrease in the price of energy due to lower natural gas prices.

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 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. In 2015, wholesale revenues from sales to affiliates decreased $105 million, or 55.6%, as compared to the prior year. In 2015, KWH sales decreased 33.9% as a result of lower-cost generation available in the Southern Company system and a 32.8% decrease in the price of energy primarily due to lower natural gas prices.

In 2015, other operating revenues decreased $14 million, or 6.3%, as compared to the prior year primarily due to decreases in co-generation steam revenues due to lower natural gas prices and transmission revenues related to the open access transmission tariff, partially offset by an increase in transmission service agreement revenues.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2016 Annual Report

Energy Sales

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

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2016	**2016**	2015	**2016**	2015
	(in billions)				
Residential	**18.4**	**1.4%**	(3.4)%	**(0.5)%**	0.1 %
Commercial	**14.1**	**(0.1)**	(0.1)	**(0.5)**	0.1
Industrial	**22.3**	**(4.6)**	(1.8)	**(4.6)**	(1.8)
Other	**0.2**	**3.8**	(4.9)	**3.8**	(4.9)
Total retail	**55.0**	**(1.5)**	(1.9)	**(2.2)%**	(0.7)%
Wholesale					
Non-affiliates	**5.9**	**37.1**	(6.3)		
Affiliates	**3.2**	**(15.7)**	(33.8)		
Total wholesale	**9.1**	**12.5**	(21.5)		
Total energy sales	**64.1**	**0.3%**	(4.9)%		

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 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.

Retail energy sales in 2015 were 1.9% lower than in 2014. Residential and commercial sales decreased 3.4% and 0.1%, respectively, due primarily to milder weather in 2015 as compared to 2014. Weather-adjusted residential and commercial sales were flat in 2015. Industrial sales decreased 1.8% in 2015 compared to 2014 as a result of a decrease in demand resulting from changes in production levels primarily in the primary metals sector. A strong dollar, low oil prices, and weak global growth conditions constrained growth in the industrial sector in 2015.

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:

	2016	2015	2014
Total generation *(in billions of KWHs)*	**60.2**	60.9	63.6
Total purchased power *(in billions of KWHs)*	**7.1**	6.3	6.6
Sources of generation *(percent)* —			
Coal	**53**	54	54
Nuclear	**23**	24	23
Gas	**19**	16	17
Hydro	**5**	6	6
Cost of fuel, generated *(in cents per net KWH)* —			
Coal	**2.75**	2.83	3.14
Nuclear	**0.78**	0.81	0.84
Gas	**2.67**	2.94	3.69
Average cost of fuel, generated *(in cents per net KWH)* (a)	**2.26**	2.34	2.68
Average cost of purchased power *(in cents per net KWH)* (b)	**4.80**	5.66	5.92

(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 $1.6 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 expenses were $1.7 billion in 2015, a decrease of $297 million, or 14.9%, compared to 2014. The decrease was primarily due to a $184 million decrease in the average cost of fuel, a $79 million decrease in the volume of KWHs generated, an $18 million decrease related to the volume of KWHs purchased, and a $16 million decrease in the average cost of purchased power.

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

Fuel

Fuel expenses were $1.3 billion in 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. Fuel expenses were $1.3 billion in 2015, a decrease of $263 million, or 16.4%, compared to 2014. The decrease was primarily due to a 20.4% decrease in the average cost of KWHs generated by natural gas, which excludes tolling agreements, a 9.9% decrease in the average cost of KWHs generated by coal, an 8.5% decrease in the volume of KWHs generated by natural gas, and a 4.0% decrease in the volume of KWHs generated by coal.

Purchased Power – Non-Affiliates

In 2016, purchased power expense from non-affiliates was $166 million , a decrease of $5 million , or 2.9% , compared to 2015. This decrease is immaterial. In 2015, purchased power expense from non-affiliates was $171 million, a decrease of $14 million, or 7.6%, compared to 2014. The decrease was primarily due to a 19.5% decrease in the average cost per KWH purchased primarily due to lower gas prices partially offset by a 15.2% increase in the amount of energy purchased due to the market availability of lower-cost generation.

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

Purchased Power – Affiliates

Purchased power expense from affiliates was $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 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. Purchased power expense from affiliates was $180 million in 2015, a decrease of $20 million, or 10.0%, compared to 2014. This decrease was primarily due to a 16.9% decrease in the amount of energy purchased due to milder weather in 2015 as compared to 2014, partially offset by an 8.3% increase in the average cost per KWH purchased related to steam support at Plant Gaston.

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 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.

In 2015, other operations and maintenance expenses increased $33 million, or 2.2%, as compared to the prior year. Employee benefit costs, including pension costs, increased $40 million. Nuclear production expenses increased $19 million primarily due to outage amortization costs. These increases were partially offset by decreases in steam production expenses of $21 million primarily due to the timing of outages and distribution expenses of $12 million primarily related to overhead line maintenance expenses.

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

Depreciation and Amortization

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. Depreciation and amortization increased $40 million, or 6.6%, in 2015 as compared to the prior year. The increase was primarily due to the amortization of $120 million of a regulatory liability for other cost of removal obligations in 2014, partially offset by decreases due to lower depreciation rates as a result of the depreciation study implemented in January 2015. See Note 3 to the financial statements under "Retail Regulatory Matters – Cost of Removal Accounting Order" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $12 million , or 3.3% , in 2016 and $12 million, or 3.4%, in 2015 as compared to prior years. These increases were primarily due to increases in state and municipal utility license tax bases primarily due to an increase in retail revenues. In addition, there were increases in ad valorem taxes primarily due to an increase in assessed value of property.

Allowance for Equity Funds Used During Construction

AFUDC equity decreased $32 million , or 53.3% , in 2016 as compared to the prior year. The decrease was primarily associated with environmental compliance and steam generation capital projects being placed in service in 2016. AFUDC equity increased $11 million, or 22.4%, in 2015 as compared to the prior year primarily due to an increase in construction projects related to environmental and steam generation. See Note 1 to financial statements under "Allowance for Funds Used During Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $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. Interest expense, net of amounts capitalized increased $19 million, or 7.5%, in 2015 as compared to the prior year. The increase in 2015 was primarily due to timing of debt issuances and redemptions, partially offset by a decrease in interest rates. See FUTURE EARNINGS POTENTIAL – "Financing Activities" herein for additional information.

Other Income (Expense), Net

Other income (expense), net increased $10 million , or 21.3% , 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. Other income (expense), net decreased $25 million, or 113.6%, in 2015 as compared to the prior year primarily due to an increase in donations and a decrease in sales of non-utility property.

Income Taxes

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 decreased $9 million , or 34.6% , in 2016 and $13 million, or 33.3%, in 2015 as compared to the prior years. The decreases were 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 electricity provided by the Company to retail customers are set by the Alabama PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

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

Environmental Matters

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

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; the Migratory Bird Treaty Act; the Bald and Golden Eagle Protection Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2016 , the Company had invested approximately $4.2 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $260 million, $349 million, and $355 million for 2016 , 2015 , and 2014 , respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $1.3 billion from 2017 through 2021 , with annual totals of approximately $471 million, $349 million, $115 million, $142 million, and $196 million for 2017 , 2018 , 2019 , 2020 , and 2021 , respectively. These estimated expenditures do not include any potential capital expenditures that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from existing, new, modified, or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Company also anticipates costs associated with ash pond closure and ground water monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are reflected in the Company's ARO liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" and Note 1 to the financial statements under "Asset Retirement Obligations and Other Cost of Removal" herein for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations, including the environmental regulations described below; the time periods over which compliance with regulations is required; individual state implementation of regulations, as applicable; the outcome of any legal challenges to the environmental rules; any additional rulemaking activities in response to legal challenges and court decisions; the cost, availability, and existing inventory of emissions allowances; the impact of future changes in generation and emissions-related technology; the Company's fuel mix; and environmental remediation requirements. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time.

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

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company.

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

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard (NAAQS). In 2008, the EPA adopted a revised eight-hour ozone NAAQS and published its final area designations in 2012. All areas within the Company's service territory have achieved attainment of the 2008 standard. In October 2015, the EPA published a more stringent eight-hour ozone NAAQS. This new standard could potentially require additional emission controls, improvements in control efficiency, and operational fuel changes and could affect the siting of new generating

facilities. States were required to recommend area designations by October 2016, and no areas within the Company's service territory were proposed for designation as nonattainment.

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

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

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

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

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

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

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

Water Quality

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

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

between November 1, 2018 and December 31, 2023 will be established in permits based on information provided for each applicable wastestream.

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

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

Coal Combustion Residuals

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

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

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

Global Climate Issues

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

These guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions and decisions on infrastructure expansion and improvements . The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through PPAs. However, the ultimate financial and operational impact of the

final rules on the Company cannot be determined at this time and will depend upon numerous factors, including the outcome of pending legal challenges, including legal challenges filed by the traditional electric operating companies, and any individual state implementation of the EPA's final guidelines in the event the rule is upheld and implemented.

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

The EPA's greenhouse gas reporting rule requires annual reporting of greenhouse gas emissions expressed in terms of metric tons of CO_2 equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2015 greenhouse gas emissions were approximately 39 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2016 greenhouse gas emissions on the same basis is approximately 38 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation, the mix of fuel sources, and other factors.

FERC Matters

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

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

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

Retail Regulatory Matters

The Company 's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the 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.

On December 1, 2016, the Company made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2017. The Rate RSE adjustment was an increase of 4.48%, or $245 million annually, effective January 1, 2017 and includes the performance based adder of 0.07%. Under the terms of Rate RSE, the maximum increase for 2018 cannot exceed 3.52%.

As of December 31, 2016, the 2016 retail return exceeded the allowed WCE range; therefore, the Company established a $73 million Rate RSE refund liability. In accordance with an order issued on February 14, 2017 by the Alabama PSC, the Company was directed to apply the full amount of the refund to reduce the under recovered balance of Rate CNP PPA.

Rate CNP PPA

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under Rate CNP. The Company may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 8, 2016, 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, 2016 through March 31, 2017. No adjustment to Rate CNP PPA is expected in 2017.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company was authorized to eliminate 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 will utilize the full amount of its $73 million Rate RSE refund liability to reduce the amount of the Rate CNP PPA under recovery and will reclassify 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 three to five 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 Rate CNP Compliance related operations and maintenance expenses and depreciation generally will have no effect on net income.

On December 6, 2016, the Alabama PSC issued a consent order that the Company leave in effect for 2017 the factors associated with the Company's compliance costs for the year 2016. As stated in the consent order, any under-collected amount for prior years will be deemed recovered before the recovery of any current year amounts. Any under recovered amounts associated with 2017 will be reflected in the 2018 filing.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company is authorized to classify any under recovered balance in Rate CNP Compliance up to approximately $36 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 three to five years. The Company's current depreciation study became effective January 1, 2017.

Rate ECR

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

On December 6, 2016, the Alabama PSC approved a decrease in the Company's Rate ECR factor from 2.030 to 2.015 cents per KWH, equal to 0.15%, or $8 million annually, based upon projected billings, effective January 1, 2017. The approved decrease in the Rate ECR factor will have no significant effect on the Company's net income, but will decrease operating cash flows related to fuel cost recovery in 2017. The rate will return to 5.910 cents per KWH in 2018, absent a further order from the Alabama PSC.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company is authorized to classify any under recovered balance in Rate ECR up to approximately $36 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 three to five years. The Company's current depreciation study became effective January 1, 2017.

Environmental Accounting Order

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

In April 2016, as part of its environmental compliance strategy, the Company 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. As a result, the Company transferred the unrecovered plant asset balances to a regulatory asset at their respective retirement dates. The regulatory asset will be amortized and recovered through Rate CNP Compliance over the 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.

Renewables

In accordance with the September 2015 Alabama PSC order approving up to 500 MWs of renewable projects, the Company has entered into agreements to purchase power from and to build 89 MWs of renewable generation sources. The terms of the agreements permit the Company to use the energy and retire the associated renewable energy credits (REC) in service of its customers or to sell RECs, separately or bundled with energy.

Income Tax Matters

Bonus Depreciation

In December 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service through 2020. The PATH Act allows for 50% bonus depreciation for 2015 through 2017, 40% bonus depreciation for 2018, and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. The extension of bonus depreciation included in the PATH Act is expected to result in approximately $230 million of positive cash flows for the 2016 tax year and approximately $180 million for the 2017 tax year. 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 air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

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

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

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.

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, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing with respect to compliance activities, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the Company expects to continue to periodically update these estimates. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Coal Combustion Residuals" herein for additional information.

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

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

Pension and Other Postretirement Benefits

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

Key elements in determining the Company's pension and other postretirement benefit expense are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, the Company discounts the future related cash flows using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. For 2015 and prior years, the Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. For 2016, the Company adopted a full yield curve approach for calculating the interest cost component whereby the discount rate for each year is applied to the liability for that specific year. As a result, the interest cost component of net periodic pension and other postretirement benefit plan expense decreased by approximately $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 $8 million or less change in total annual benefit expense and a $105 million or less change in projected obligations.

The Company recorded pension costs of $11 million in 2016, $48 million in 2015, and $23 million in 2014. Postretirement benefit costs for the Company were $4 million, $5 million, and $4 million in 2016, 2015, and 2014, 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

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

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

(including unbilled revenues) and the adoption of ASC 606 will not result in a significant shift in the timing of revenue recognition for such sales.

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

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

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

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

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

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2016. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to 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 2017 through 2019, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt issuances, borrowings from financial institutions, preferred and preference stock issuances, or capital contributions from Southern Company. 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, 2016 as compared to December 31, 2015. On December 19, 2016, the Company voluntarily contributed $129 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated during 2017 . 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 $ 1.9 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 provided from operating activities totaled $2.1 billion for 2015, an increase of $433 million as compared to 2014. The increase in cash provided from operating activities was primarily due to the timing of income tax payments and refunds associated with bonus depreciation and collection of fuel cost recovery revenues, partially offset by the timing of payment of accounts payable.

Net cash used for investing activities totaled $1.4 billion for 2016, $1.5 billion for 2015, and $1.6 billion for 2014. These activities were primarily related to gross property additions for distribution, environmental, transmission, and steam generation assets. In 2014, these activities also related to gross property additions for nuclear fuel assets.

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. Net cash used for financing activities totaled $733 million in 2015 primarily due to the payment of common stock dividends and redemptions of securities, partially offset by issuances of long-term debt. 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 2016 included an increase of $905 million in property, plant, and equipment primarily due to additions to environmental, steam generation, distribution, and transmission facilities, an increase of $413 million in accumulated deferred income taxes primarily as a result of bonus depreciation, and an increase of $361 million in securities due within one year. Other significant changes include a decrease of $310 million in construction work in progress primarily due to environmental equipment related to steam generation facilities being placed in service.

The Company's ratio of common equity to total capitalization plus short-term debt was 46.2% and 45.6% at December 31, 2016 and 2015, 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, short-term debt, term loans, external security issuances, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, 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.

At December 31, 2016, the Company's current liabilities exceeded current assets by $0.1 billion. 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, 2016, the Company had approximately $420 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2016 were as follows:

Expires					Expires Within One Year	
2017	2018	2020	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.

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, 2016, the Company was in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of 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 $890 million as of December 31, 2016. In addition, at December 31, 2016, the Company had $87 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.

The Company had no short-term borrowings outstanding at December 31, 2016, 2015, and 2014. Details of commercial paper borrowings were as follows:

	Short-term Debt During the Period (*)		
	Average Amount Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*
December 31, 2016	**$ 16**	**0.6%**	**$ 200**
December 31, 2015	$ 14	0.2%	$ 100
December 31, 2014	$ 13	0.2%	$ 300

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

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 January 2016, the Company issued $400 million aggregate principal amount of Series 2016A 4.30% Senior Notes due January 2, 2046. The proceeds were used to repay at maturity $200 million aggregate principal amount of the Company's Series FF 5.20% Senior Notes due January 15, 2016 and for general corporate purposes, including the Company's continuous construction program.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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In March 2016, the Company entered into three bank term loan agreements with maturity dates of March 2021, in an aggregate principal amount of $45 million, one of which bears interest at 2.38% per annum and two of which bear interest based on three-month LIBOR.

Subsequent to December 31, 2016, the Company repaid at maturity $200 million aggregate principal amount of its Series 2007A 5.55% Senior Notes due February 1, 2017.

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

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and/or 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, 2016 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	$	332

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

Market Price Risk

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

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives designated as hedges. The weighted average interest rate on $1.1 billion of long-term variable interest rate exposure at January 1, 2017 was 1.38%. 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 January 1, 2017. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and 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, 2016 when compared to the year ended December 31, 2015.

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:

	2016 Changes	2015 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$ (54)	$ (52)
Contracts realized or settled	39	41
Current period changes [*]	27	(43)
Contracts outstanding at the end of the period, assets (liabilities), net	$ 12	$ (54)

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

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

	2016	2015
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	68	44
Commodity – Natural gas options	6	6
Total hedge volume	74	50

The weighted average swap contract cost below market prices was approximately $0.14 per mmBtu as of December 31, 2016 and above market prices was approximately $1.13 per mmBtu as of December 31, 2015. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. Substantially all of the natural gas hedge gains and losses are recovered through the Company's retail energy cost recovery clause.

At December 31, 2016 and 2015, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the 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 all Level 2 of the fair value hierarchy, at December 31, 2016 were as follows:

	Fair Value Measurements December 31, 2016		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
	(in millions)		
Level 1	$ —	$ —	$ —
Level 2	12	8	4
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ 12	$ 8	$ 4

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

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to total $1.9 billion for 2017, $1.6 billion for 2018, $1.2 billion for 2019, $1.2 billion for 2020, and $1.2 billion for 2021. The construction program includes capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these amounts are $0.5 billion for 2017, $0.3 billion for 2018, $0.1 billion for 2019, $0.1 billion for 2020, and $0.2 billion for 2021. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from new, existing, modified, or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and "– Global Climate Issues" herein for additional information.

The Company also anticipates costs associated with closure 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 $31 million, $26 million, $100 million, $105 million, and $107 million for the years 2017, 2018, 2019, 2020, and 2021, respectively. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information. Costs associated with the CCR Rule are expected to be recovered through Rate CNP Compliance.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing 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 and preference stock dividends, leases,

and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

Contractual obligations at December 31, 2016 were as follows:

	2017	2018-2019	2020-2021	After 2021	Total
			(in millions)		
Long-term debt [(a)] —					
Principal	$ 561	$ 200	$ 560	$ 5,827	$ 7,148
Interest	290	521	492	4,013	5,316
Preferred and preference stock dividends [(b)]	17	35	35	—	87
Financial derivative obligations [(c)]	5	4	—	—	9
Operating leases [(d)]	14	20	16	10	60
Capital Lease	1	1	1	3	6
Purchase commitments —					
Capital [(e)]	1,782	2,554	2,185	—	6,521
Fuel [(f)]	1,069	1,404	631	355	3,459
Purchased power [(g)]	81	174	189	722	1,166
Other [(h)]	44	86	52	274	456
Pension and other postretirement benefit plans [(i)]	19	38	—	—	57
Total	$ 3,883	$ 5,037	$ 4,161	$ 11,204	$ 24,285

(a) All amounts are reflected based on final maturity dates. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 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.

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

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

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

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

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

(g) Estimated minimum long-term obligations for various long-term commitments for the purchase of capacity and energy. Amounts are related to the Company's certificated PPAs which include MWs purchased from gas-fired and wind-powered facilities.

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

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

Cautionary Statement Regarding Forward-Looking Statements

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

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

STATEMENTS OF INCOME
For the Years Ended December 31, 2016 , 2015 , and 2014
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	2016	2015	2014
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 5,322**	$ 5,234	$ 5,249
Wholesale revenues, non-affiliates	**283**	241	281
Wholesale revenues, affiliates	**69**	84	189
Other revenues	**215**	209	223
Total operating revenues	**5,889**	5,768	5,942
Operating Expenses:			
Fuel	**1,297**	1,342	1,605
Purchased power, non-affiliates	**166**	171	185
Purchased power, affiliates	**168**	180	200
Other operations and maintenance	**1,510**	1,501	1,468
Depreciation and amortization	**703**	643	603
Taxes other than income taxes	**380**	368	356
Total operating expenses	**4,224**	4,205	4,417
Operating Income	**1,665**	1,563	1,525
Other Income and (Expense):			
Allowance for equity funds used during construction	**28**	60	49
Interest expense, net of amounts capitalized	**(302)**	(274)	(255)
Other income (expense), net	**(21)**	(32)	(7)
Total other income and (expense)	**(295)**	(246)	(213)
Earnings Before Income Taxes	**1,370**	1,317	1,312
Income taxes	**531**	506	512
Net Income	**839**	811	800
Dividends on Preferred and Preference Stock	**17**	26	39
Net Income After Dividends on Preferred and Preference Stock	**$ 822**	$ 785	$ 761

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2016 , 2015 , and 2014
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	2016	2015	2014
		(in millions)	
Net Income	**$ 839**	$ 811	$ 800
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(1), $(3), and $(3), respectively	**(2)**	(5)	(5)
Reclassification adjustment for amounts included in net income, net of tax of $2, $1, and $1, respectively	**4**	2	2
Total other comprehensive income (loss)	**2**	(3)	(3)
Comprehensive Income	**$ 841**	$ 808	$ 797

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2016 , 2015 , and 2014
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	2016	2015	2014
		(in millions)	
Operating Activities:			
Net income	**$ 839**	$ 811	$ 800
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**844**	780	724
Deferred income taxes	**407**	388	270
Allowance for equity funds used during construction	**(28)**	(60)	(49)
Pension, postretirement, and other employee benefits	**(27)**	20	(61)
Pension and postretirement funding	**(133)**	—	—
Other deferred charges – affiliated	**(50)**	—	—
Other, net	**(25)**	(5)	29
Changes in certain current assets and liabilities —			
-Receivables	**94**	(160)	(58)
-Fossil fuel stock	**34**	28	61
-Other current assets	**(33)**	12	(29)
-Accounts payable	**73**	3	157
-Accrued taxes	**93**	138	(199)
-Retail fuel cost over recovery	**(162)**	191	5
-Other current liabilities	**23**	(4)	59
Net cash provided from operating activities	**1,949**	2,142	1,709
Investing Activities:			
Property additions	**(1,272)**	(1,367)	(1,457)
Nuclear decommissioning trust fund purchases	**(352)**	(439)	(245)
Nuclear decommissioning trust fund sales	**351**	438	244
Cost of removal net of salvage	**(94)**	(71)	(77)
Change in construction payables	**(37)**	(15)	(10)
Other investing activities	**(34)**	(34)	(22)
Net cash used for investing activities	**(1,438)**	(1,488)	(1,567)
Financing Activities:			
Proceeds —			
Senior notes	**400**	975	400
Pollution control revenue bonds	**—**	80	254
Other long-term debt	**45**	—	—
Capital contributions from parent company	**260**	22	28
Redemptions and repurchases —			
Senior notes	**(200)**	(650)	—
Preferred and preference stock	**—**	(412)	—
Pollution control revenue bonds	**—**	(134)	(254)
Payment of common stock dividends	**(765)**	(571)	(550)
Other financing activities	**(25)**	(43)	(42)
Net cash used for financing activities	**(285)**	(733)	(164)
Net Change in Cash and Cash Equivalents	**226**	(79)	(22)
Cash and Cash Equivalents at Beginning of Year	**194**	273	295
Cash and Cash Equivalents at End of Year	**$ 420**	$ 194	$ 273
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $11, $22, and $18 capitalized, respectively)	**$ 277**	$ 250	$ 231
Income taxes (net of refunds)	**(108)**	121	436
Noncash transactions — accrued property additions at year-end	**84**	121	8

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

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

Assets		2016		2015
		(in millions)		
Current Assets:				
Cash and cash equivalents	$	420	$	194
Receivables —				
Customer accounts receivable		348		375
Unbilled revenues		146		119
Income taxes receivable, current		—		142
Other accounts and notes receivable		27		20
Affiliated		40		50
Accumulated provision for uncollectible accounts		(10)		(10)
Fossil fuel stock		205		239
Materials and supplies		435		398
Prepaid expenses		34		83
Other regulatory assets, current		149		182
Other current assets		11		9
Total current assets		1,805		1,801
Property, Plant, and Equipment:				
In service		26,031		24,750
Less accumulated provision for depreciation		9,112		8,736
Plant in service, net of depreciation		16,919		16,014
Nuclear fuel, at amortized cost		336		363
Construction work in progress		491		801
Total property, plant, and equipment		17,746		17,178
Other Property and Investments:				
Equity investments in unconsolidated subsidiaries		66		71
Nuclear decommissioning trusts, at fair value		792		737
Miscellaneous property and investments		112		96
Total other property and investments		970		904
Deferred Charges and Other Assets:				
Deferred charges related to income taxes		525		522
Deferred under recovered regulatory clause revenues		150		99
Other regulatory assets, deferred		1,157		1,114
Other deferred charges and assets		163		103
Total deferred charges and other assets		1,995		1,838
Total Assets	$	22,516	$	21,721

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

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

Liabilities and Stockholder's Equity		**2016**		2015
		(in millions)		
Current Liabilities:				
Securities due within one year	**$**	**561**	$	200
Accounts payable —				
Affiliated		**297**		278
Other		**433**		410
Customer deposits		**88**		88
Accrued taxes —				
Accrued income taxes		**45**		—
Other accrued taxes		**42**		38
Accrued interest		**78**		73
Accrued compensation		**193**		175
Other regulatory liabilities, current		**85**		240
Other current liabilities		**76**		93
Total current liabilities		**1,898**		1,595
Long-Term Debt (See accompanying statements)		**6,535**		6,654
Deferred Credits and Other Liabilities:				
Accumulated deferred income taxes		**4,654**		4,241
Deferred credits related to income taxes		**65**		70
Accumulated deferred investment tax credits		**110**		118
Employee benefit obligations		**300**		388
Asset retirement obligations		**1,503**		1,448
Other cost of removal obligations		**684**		722
Other regulatory liabilities, deferred		**100**		136
Other deferred credits and liabilities		**63**		76
Total deferred credits and other liabilities		**7,479**		7,199
Total Liabilities		**15,912**		15,448
Redeemable Preferred Stock (See accompanying statements)		**85**		85
Preference Stock (See accompanying statements)		**196**		196
Common Stockholder's Equity (See accompanying statements)		**6,323**		5,992
Total Liabilities and Stockholder's Equity	**$**	**22,516**	$	21,721
Commitments and Contingent Matters (See notes)				

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

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

	2016	2015	2016	2015
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term debt payable to affiliated trusts —				
Variable rate (3.95% at 1/1/17) due 2042	**$ 206**	$ 206		
Long-term notes payable —				
5.20% due 2016	**—**	200		
5.50% to 5.55% due 2017	**525**	525		
5.125% due 2019	**200**	200		
3.375% due 2020	**250**	250		
2.38% to 3.95% due 2021	**220**	200		
2.80% to 6.125% due 2022-2046	**4,625**	4,225		
Variable rates (1.87% to 2.10% at 1/1/17) due 2021	**25**	—		
Total long-term notes payable	**5,845**	5,600		
Other long-term debt —				
Pollution control revenue bonds —				
0.65% to 1.65% due 2034	**207**	287		
Variable rates (0.77% to 0.79% at 1/1/17) due 2017	**36**	36		
Variable rates (0.82% to 0.86% at 1/1/17) due 2021	**65**	65		
Variable rates (0.77% to 0.82% at 1/1/17) due 2024-2038	**788**	709		
Total other long-term debt	**1,096**	1,097		
Capitalized lease obligations	**4**	5		
Unamortized debt premium (discount), net	**(9)**	(9)		
Unamortized debt issuance expense	**(46)**	(45)		
Total long-term debt (annual interest requirement — $290 million)	**7,096**	6,854		
Less amount due within one year	**561**	200		
Long-term debt excluding amount due within one year	**6,535**	6,654	**49.7%**	51.4%
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 — 5.83%				
Authorized — 27,500,000 shares				
Outstanding — 1,520,000 shares: $25 stated value				
(annual dividend requirement — $4 million)	**37**	37		
Total redeemable preferred stock	**85**	85	**0.7**	0.7
Preference Stock:				
Authorized — 40,000,000 shares				
Outstanding — $1 par value — 6.45% to 6.50%				
— 8,000,000 shares (non-cumulative): $25 stated value				
(annual dividend requirement — $13 million)	**196**	196	**1.5**	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	**2,613**	2,341		
Retained earnings	**2,518**	2,461		
Accumulated other comprehensive loss	**(30)**	(32)		
Total common stockholder's equity	**6,323**	5,992	**48.1**	46.4

Total Capitalization	$	13,139	$	12,927	100.0%	100.0%

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

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2016 , 2015 , and 2014
Alabama Power Company 2016 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
				(in millions)		
Balance at December 31, 2013	31	$ 1,222	$ 2,262	$ 2,044	$ (26)	$ 5,502
Net income after dividends on preferred and preference stock	—	—	—	761	—	761
Capital contributions from parent company	—	—	42	—	—	42
Other comprehensive income (loss)	—	—	—	—	(3)	(3)
Cash dividends on common stock	—	—	—	(550)	—	(550)
Balance at December 31, 2014	31	1,222	2,304	2,255	(29)	5,752
Net income after dividends on preferred and preference stock	—	—	—	785	—	785
Capital contributions from parent company	—	—	37	—	—	37
Other comprehensive income (loss)	—	—	—	—	(3)	(3)
Cash dividends on common stock	—	—	—	(571)	—	(571)
Other	—	—	—	(8)	—	(8)
Balance at December 31, 2015	**31**	**1,222**	**2,341**	**2,461**	**(32)**	**5,992**
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**

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

NOTES TO FINANCIAL STATEMENTS
Alabama Power Company 2016 Annual Report

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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 constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern LINC provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and for other electric services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants, including the Company's Plant 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

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

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

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

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

On February 25, 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition,

measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged . ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company is currently evaluating the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

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

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

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Costs for these services amounted to $460 million , $438 million , and $400 million during 2016 , 2015 , and 2014 , respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has an agreement with 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 $249 million , $243 million , and $234 million during 2016 , 2015 , and 2014 , 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 $13 million in 2016 , $11 million in 2015 , and $13 million in 2014 . Mississippi Power also reimbursed the Company for any direct fuel purchases delivered from one of the Company's transfer facilities. There were no fuel purchases in 2016. Fuel purchases were $8 million and $34 million in 2015 and 2014 , respectively. 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 $12 million in 2016, $14 million in 2015, and $12 million in 2014 and expects to recover a total of approximately $73 million from 2017 through 2023 from Gulf Power.

On September 1, 2016, Southern Company Gas acquired a 50% equity interest in Southern Natural Gas Company, L.L.C. (SNG). Prior to completion of the acquisition, SCS, as agent for the Company, had entered into a long-term interstate natural gas transportation agreement with SNG. The interstate transportation service provided to the Company by SNG pursuant to this

agreement is governed by the terms and conditions of SNG's natural gas tariff and is subject to FERC regulation. For the period subsequent to Southern Company Gas' investment in SNG through December 31, 2016, transportation costs under this agreement were approximately $2 million .

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2016 , 2015 , or 2014 .

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.

NOTES (continued)
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Regulatory Assets and Liabilities

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

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

	2016	2015	Note
	(in millions)		
Retiree benefit plans	$ 947	$ 903	(i,j)
Deferred income tax charges	526	522	(a,k)
Under/(over) recovered regulatory clause revenues	76	(97)	(d)
Nuclear outage	70	53	(d)
Remaining net book value of retired assets	69	76	(l)
Vacation pay	69	66	(c,j)
Loss on reacquired debt	68	75	(b)
Other regulatory assets	50	53	(f)
Asset retirement obligations	12	(40)	(a)
Fuel-hedging losses	1	55	(e,j)
Other cost of removal obligations	(684)	(722)	(a)
Natural disaster reserve	(69)	(75)	(h)
Deferred income tax credits	(65)	(70)	(a)
Other regulatory liabilities	(23)	(8)	(e,g)
Total regulatory assets (liabilities), net	$ 1,047	$ 791	

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

(a) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 50 years . Asset retirement and 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 $16 million for 2016 and $17 million for 2015 for the retiree Medicare drug subsidy, which is recovered and amortized, as approved by the Alabama PSC, over the average remaining service period which may range up to 15 years .

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

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

Revenues

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amount billable under the contract terms. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company 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:

	2016	2015
	(in millions)	
Generation	**$ 13,551**	$ 12,820
Transmission	**3,921**	3,773
Distribution	**6,707**	6,432
General	**1,840**	1,713
Plant acquisition adjustment	**12**	12
Total plant in service	**$ 26,031**	$ 24,750

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.

NOTES (continued)
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Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.0% in 2016 , 2.9% in 2015 , and 3.3% in 2014 . 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. The revised rates will not have a significant impact on depreciation expense in 2017.

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 April 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:

	2016	2015
	(in millions)	
Balance at beginning of year	**$ 1,448**	$ 829
Liabilities incurred	**5**	402
Liabilities settled	**(25)**	(3)
Accretion	**73**	53
Cash flow revisions	**32**	167
Balance at end of year	**$ 1,533**	$ 1,448

The increase in liabilities incurred and cash flow revisions in 2016 and 2015 are 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, 2016 using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure in place. As further analysis is performed, including

evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing with respect to compliance activities, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the Company expects to continue to periodically update these estimates.

Nuclear Decommissioning

The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the 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, 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. At December 31, 2015 , investment securities in the Funds totaled $734 million , consisting of equity securities of $521 million , debt securities of $191 million , and $22 million of other securities. 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 $351 million , $438 million , and $244 million in 2016 , 2015 , and 2014 , respectively, all of which were reinvested. For 2016 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $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 . For 2014 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $54 million , which included $19 million related to unrealized gains on securities held in the Funds at December 31, 2014 . 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:

	2016	2015
	(in millions)	
External trust funds	**$ 790**	$ 734
Internal reserves	**19**	20
Total	**$ 809**	$ 754

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, 2016 based on the most current study performed in 2013 for Plant Farley are as follows:

Decommissioning periods:	
Beginning year	2037
Completion year	2076

	(in millions)
Site study costs:	
Radiated structures	$ 1,362
Non-radiated structures	80
Total site study costs	$ 1,442

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

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

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

Allowance for Funds Used During Construction

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 8.4% in 2016 , 8.7% in 2015 , and 8.8% in 2014 . AFUDC, net of income taxes, as a percent of net income after dividends on preferred and preference stock was 4.2% in 2016 , 9.3% in 2015 , and 7.9% in 2014 .

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.

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

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

Comprehensive Income

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

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). On December 19, 2016, the Company voluntarily contributed $129 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2017 . The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the Alabama PSC and the FERC. For the year ending December 31, 2017 , 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:	2016	2015	2014
Pension plans			
Discount rate – benefit obligations	**4.67%**	4.18%	5.02%
Discount rate – interest costs	**3.90**	4.18	5.02
Discount rate – service costs	**5.07**	4.49	5.02
Expected long-term return on plan assets	**8.20**	8.20	8.20
Annual salary increase	**4.46**	3.59	3.59
Other postretirement benefit plans			
Discount rate – benefit obligations	**4.51%**	4.04%	4.86%
Discount rate – interest costs	**3.69**	4.04	4.86
Discount rate – service costs	**4.96**	4.40	4.86
Expected long-term return on plan assets	**6.83**	7.17	7.34
Annual salary increase	**4.46**	3.59	3.59

Assumptions used to determine benefit obligations:	2016	2015
Pension plans		
Discount rate	**4.44%**	4.67%
Annual salary increase	**4.46**	4.46
Other postretirement benefit plans		
Discount rate	**4.27%**	4.51%
Annual salary increase	**4.46**	4.46

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

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

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

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

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 28	$ 24
Service and interest costs	1	1

Pension Plans

The total accumulated benefit obligation for the pension plans was $2.4 billion at December 31, 2016 and $2.3 billion at December 31, 2015 . Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2016 and 2015 were as follows:

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,506**	$ 2,592
Service cost	**57**	59
Interest cost	**95**	106
Benefits paid	**(109)**	(120)
Actuarial (gain) loss	**114**	(131)
Balance at end of year	**2,663**	2,506
Change in plan assets		
Fair value of plan assets at beginning of year	**2,279**	2,396
Actual return (loss) on plan assets	**206**	(9)
Employer contributions	**141**	12
Benefits paid	**(109)**	(120)
Fair value of plan assets at end of year	**2,517**	2,279
Accrued liability	**$ (146)**	$ (227)

At December 31, 2016 , the projected benefit obligations for the qualified and non-qualified pension plans were $2.5 billion and $124 million , respectively. All pension plan assets are related to the qualified pension plan.

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

	2016	2015
	(in millions)	
Other regulatory assets, deferred	**$ 870**	$ 822
Other current liabilities	**(12)**	(11)
Employee benefit obligations	**(134)**	(216)

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

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	2016	2015	Estimated Amortization in 2017
		(in millions)	
Prior service cost	$ 10	$ 6	$ 3
Net (gain) loss	860	816	42
Regulatory assets	$ 870	$ 822	

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

	2016	2015
	(in millions)	
Regulatory assets:		
Beginning balance	$ 822	$ 827
Net (gain) loss	84	56
Change in prior service costs	7	—
Reclassification adjustments:		
Amortization of prior service costs	(3)	(6)
Amortization of net gain (loss)	(40)	(55)
Total reclassification adjustments	(43)	(61)
Total change	48	(5)
Ending balance	$ 870	$ 822

Components of net periodic pension cost were as follows:

	2016	2015	2014
		(in millions)	
Service cost	$ 57	$ 59	$ 48
Interest cost	95	106	103
Expected return on plan assets	(184)	(178)	(168)
Recognized net (gain) loss	40	55	31
Net amortization	3	6	7
Net periodic pension cost	$ 11	$ 48	$ 21

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

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

	Benefit Payments
	(in millions)
2017	$ 122
2018	127
2019	132
2020	137
2021	142
2022 to 2026	777

Other Postretirement Benefits

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

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 505**	$ 503
Service cost	**5**	6
Interest cost	**18**	20
Benefits paid	**(28)**	(27)
Actuarial (gain) loss	**(1)**	(7)
Plan amendment	**—**	7
Retiree drug subsidy	**2**	3
Balance at end of year	**501**	505
Change in plan assets		
Fair value of plan assets at beginning of year	**363**	392
Actual return (loss) on plan assets	**23**	(6)
Employer contributions	**7**	1
Benefits paid	**(26)**	(24)
Fair value of plan assets at end of year	**367**	363
Accrued liability	**$ (134)**	$ (142)

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

	2016	2015
	(in millions)	
Other regulatory assets, deferred	**$ 86**	$ 95
Other regulatory liabilities, deferred	**(10)**	(13)
Employee benefit obligations	**(134)**	(142)

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

	2016	2015	**Estimated Amortization in 2017**
		(in millions)	
Prior service cost	**$ 15**	$ 19	**$ 4**
Net (gain) loss	**61**	63	**1**
Net regulatory assets	**$ 76**	$ 82	

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

	2016	2015
	(in millions)	
Net regulatory assets (liabilities):		
Beginning balance	**$ 82**	$ 54
Net (gain) loss	**—**	25
Change in prior service costs	**—**	8
Reclassification adjustments:		
Amortization of prior service costs	**(4)**	(3)
Amortization of net gain (loss)	**(2)**	(2)
Total reclassification adjustments	**(6)**	(5)
Total change	**(6)**	28
Ending balance	**$ 76**	$ 82

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

	2016	2015	2014
		(in millions)	
Service cost	**$ 5**	$ 6	$ 5
Interest cost	**18**	20	20
Expected return on plan assets	**(25)**	(26)	(25)
Net amortization	**6**	5	4
Net periodic postretirement benefit cost	**$ 4**	$ 5	$ 4

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

	Benefit Payments	Subsidy Receipts	Total
		(in millions)	
2017	$ 32	$ (3)	$ 29
2018	33	(3)	30
2019	34	(4)	30
2020	35	(4)	31
2021	36	(4)	32
2022 to 2026	183	(22)	161

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2016 and 2015 , along with the targeted mix of assets for each plan, is presented below:

	Target	**2016**	2015
Pension plan assets:			
Domestic equity	26%	**29%**	30%
International equity	25	**22**	23
Fixed income	23	**29**	23
Special situations	3	**2**	2
Real estate investments	14	**13**	16
Private equity	9	**5**	6
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	46%	**44%**	45%
International equity	22	**20**	20
Domestic fixed income	24	**29**	27
Special situations	1	**1**	1
Real estate investments	4	**4**	5
Private equity	3	**2**	2
Total	100%	**100%**	100%

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

formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

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

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

Benefit Plan Asset Fair Values

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

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

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

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

	Fair Value Measurements Using				
As of December 31, 2016:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Assets:					
Domestic equity [(*)]	$ 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. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

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As of December 31, 2015:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Assets:					
Domestic equity [*]	$ 403	$ 168	$ —	$ —	$ 571
International equity [*]	294	244	—	—	538
Fixed income:					
U.S. Treasury, government, and agency bonds	—	112	—	—	112
Mortgage- and asset-backed securities	—	49	—	—	49
Corporate bonds	—	280	—	—	280
Pooled funds	—	123	—	—	123
Cash equivalents and other	—	36	—	—	36
Real estate investments	74	—	—	301	375
Private equity	—	—	—	157	157
Total	$ 771	$ 1,012	$ —	$ 458	$ 2,241

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

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

	Fair Value Measurements Using				
As of December 31, 2016:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Assets:					
Domestic equity (*)	$ 51	$ 10	$ —	$ —	$ 61
International equity (*)	13	12	—	—	25
Fixed income:					
U.S. Treasury, government, and agency bonds	—	7	—	—	7
Mortgage- and asset-backed securities	—	—	—	—	—
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. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

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As of December 31, 2015:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Assets:					
Domestic equity (*)	$ 57	$ 8	$ —	$ —	$ 65
International equity (*)	14	12	—	—	26
Fixed income:					
U.S. Treasury, government, and agency bonds	—	8	—	—	8
Mortgage- and asset-backed securities	—	2	—	—	2
Corporate bonds	—	13	—	—	13
Pooled funds	—	6	—	—	6
Cash equivalents and other	1	2	—	—	3
Trust-owned life insurance	—	212	—	—	212
Real estate investments	5	—	—	14	19
Private equity	—	—	—	7	7
Total	$ 77	$ 263	$ —	$ 21	$ 361

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

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2016 , 2015 , and 2014 were $23 million , $22 million , and $21 million , respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

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

Environmental Matters

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up affected sites. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year

presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation.

Nuclear Fuel Disposal Costs

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

In 2014, the Court of Federal Claims entered a judgment in favor of the Company in its spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. In March 2015, the Company recovered approximately $26 million , which was applied to reduce the cost of service for the benefit of customers.

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

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

FERC Matters

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

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

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

Retail Regulatory Matters

Rate 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.

On December 1, 2016, the Company made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2017. The Rate RSE adjustment was an increase of 4.48% , or $245 million annually, effective January 1, 2017 and includes the performance based adder of 0.07% . Under the terms of Rate RSE, the maximum increase for 2018 cannot exceed 3.52% .

As of December 31, 2016, the 2016 retail return exceeded the allowed WCE range; therefore, the Company established a $73 million Rate RSE refund liability. In accordance with an order issued on February 14, 2017 by the Alabama PSC, the Company was directed to apply the full amount of the refund to reduce the under recovered balance of Rate CNP PPA.

Rate CNP PPA

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under Rate CNP. The Company may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 8, 2016, 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, 2016 through March 31, 2017. No adjustment to Rate CNP PPA is expected in 2017. As of December 31, 2016 and 2015, the Company had an under recovered certificated PPA balance of $142 million and $99 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 was authorized to eliminate 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 will utilize the full amount of its $73 million Rate RSE refund liability to reduce the amount of the Rate CNP PPA under recovery and will reclassify 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 three to five 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 compliance related operations and maintenance expenses and depreciation generally will have no effect on net income.

On December 6, 2016, the Alabama PSC issued a consent order that the Company leave in effect for 2017 the factors associated with the Company's compliance costs for the year 2016. As stated in the consent order, any under-collected amount for prior years will be deemed recovered before the recovery of any current year amounts. Any under recovered amounts associated with 2017 will be reflected in the 2018 filing. As of December 31, 2016, the Company had a deferred under recovered regulatory clause revenues balance of $9 million .

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company is authorized to classify any under recovered balance in Rate CNP Compliance up to approximately $36 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 three to five years . The Company's current depreciation study became effective January 1, 2017.

Rate ECR

The Company has established energy cost recovery rates under the Company's Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or

under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH. In December 2015, the Alabama PSC issued a consent order that the Company decrease the Rate ECR factor from 2.681 cents per KWH to 2.030 cents per KWH.

On December 6, 2016, the Alabama PSC approved a decrease in the Company's Rate ECR factor from 2.030 to 2.015 cents per KWH, equal to 0.15% , or $8 million annually, based upon projected billings, effective January 1, 2017. The rate will return to 5.910 cents per KWH in 2018 absent a further order from the Alabama PSC.

At December 31, 2016 and 2015, the Company's over recovered fuel costs totaled $76 million and $238 million , respectively, and are 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.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company is authorized to classify any under recovered balance in Rate ECR up to approximately $36 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 three to five years . The Company's current depreciation study became effective January 1, 2017.

Rate NDR

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

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

Environmental Accounting Order

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

In April 2015, as part of its environmental compliance strategy, the Company retired Plant Gorgas Units 6 and 7 (200 MWs). Additionally, in April 2015, the Company ceased using coal at Plant Barry Units 1 and 2 (250 MWs), but such units will remain available on a limited basis with natural gas as the fuel source. In accordance with the joint stipulation entered in connection with a civil enforcement action by the EPA, the Company retired Plant Barry Unit 3 (225 MWs) in August 2015 and it is no longer available for generation. In April 2016, as part of its environmental compliance strategy, the Company 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 a regulatory asset at their respective retirement dates. The regulatory asset will be 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.

Cost of Removal Accounting Order

In accordance with an accounting order issued by the Alabama PSC, in 2014, the Company fully amortized the balance of $123 million in certain regulatory asset accounts and offset this amortization expense with the amortization of $120 million of the regulatory liability for other cost of removal obligations. The regulatory asset accounts fully amortized and terminated as of December 31, 2014 represented costs previously deferred under a compliance and pension cost accounting order as well as a non-nuclear outage accounting order, which were approved by the Alabama PSC in 2012 and 2013, respectively. Approximately $95 million of non-nuclear outage costs and $28 million of compliance and pension costs previously deferred were fully amortized in 2014.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Georgia Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Georgia Power under a power contract. The Company and Georgia Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and ROE. The Company's share of purchased power totaled $55 million in 2016 , $76 million in 2015 , and $84 million in 2014 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, 2016 , the capitalization of SEGCO consisted of $108 million of equity and $125 million of long-term debt on which the annual interest requirement is $3 million . In addition, SEGCO had short-term debt outstanding of $38 million . SEGCO paid $24 million of dividends in 2016 compared to an immaterial amount in 2015 and 2014 , of which one-half of each was paid to the Company. In addition, the Company recognizes 50% of SEGCO's net income.

SEGCO added natural gas as a fuel source for 1,000 MWs of its generating capacity in 2015. In April 2016, natural gas became the primary fuel source. The Company, which owns and operates a generating unit adjacent to the SEGCO generating units, has entered into a joint ownership agreement with SEGCO for the ownership of 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, 2016 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)	$ 168	$ 66	$ 1
Plant Miller					
Units 1 and 2	1,320	91.84% (2)	1,657	587	23

(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.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2016	2015	2014
		(in millions)	
Federal —			
Current	**$ 103**	$ 110	$ 198
Deferred	**339**	320	225
	442	430	423
State —			
Current	**20**	8	44
Deferred	**69**	68	45
	89	76	89
Total	**$ 531**	$ 506	$ 512

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

	2016	2015
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	**$ 4,307**	$ 3,917
Property basis differences	**456**	456
Premium on reacquired debt	**26**	28
Employee benefit obligations	**201**	200
Regulatory assets associated with employee benefit obligations	**393**	375
Asset retirement obligations	**289**	289
Regulatory assets associated with asset retirement obligations	**347**	312
Other	**179**	175
Total	**6,198**	5,752
Deferred tax assets —		
Federal effect of state deferred taxes	**266**	242
Unbilled fuel revenue	**36**	39
Storm reserve	**21**	23
Employee benefit obligations	**427**	407
Other comprehensive losses	**19**	20
Asset retirement obligations	**636**	600
Other	**139**	180
Total	**1,544**	1,511
Accumulated deferred income taxes, net	**$ 4,654**	$ 4,241

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

At December 31, 2016 , the tax-related regulatory assets to be recovered from customers were $526 million . These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest.

At December 31, 2016 , the tax-related regulatory liabilities to be credited to customers were $65 million . These liabilities are primarily attributable to unamortized ITCs.

In accordance with regulatory requirements, deferred federal ITCs are amortized over the average life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $8 million annually in 2016, 2015, and 2014. At December 31, 2016 , all ITCs available to reduce federal income taxes payable had been utilized.

Effective Tax Rate

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

	2016	2015	2014
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**4.2**	3.8	4.4
Non-deductible book depreciation	**1.0**	1.2	1.1
AFUDC equity	**(0.7)**	(1.6)	(1.3)
Other	**(0.7)**	—	(0.2)
Effective income tax rate	**38.8%**	38.4%	39.0%

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

Unrecognized Tax Benefits

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

6. FINANCING

Long-Term Debt Payable to an Affiliated Trust

The Company has formed a wholly-owned trust subsidiary for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $206 million as of December 31, 2016 and 2015 , 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, 2016 and 2015 , 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, 2016 and 2015 , the Company had $561 million and $200 million , respectively, of senior notes and pollution control revenue bonds due within one year.

Maturities through 2021 applicable to total long-term debt are as follows: $561 million in 2017 ; $200 million in 2019 ; $250 million in 2020 ; and $310 million in 2021 . There are no material scheduled maturities in 2018.

Bank Term Loans

In March 2016, the Company entered into three bank term loan agreements with maturity dates of March 2021, in an aggregate principal amount of $45 million , one of which bears interest at 2.38% per annum and two of which bear interest based on three-month LIBOR.

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, 2016 , 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 2016.

The Company had $1.1 billion of tax-exempt pollution control revenue bond obligations outstanding at each of December 31, 2016 and 2015 , including pollution control revenue bonds due within one year.

Senior Notes

In January 2016, the Company issued $400 million aggregate principal amount of Series 2016A 4.30% Senior Notes due January 2, 2046. The proceeds were used to repay at maturity $200 million aggregate principal amount of the Company's Series FF 5.20% Senior Notes due January 15, 2016 and for general corporate purposes, including the Company's continuous construction program.

At December 31, 2016 and 2015 , the Company had $5.8 billion and $5.6 billion of senior notes outstanding, respectively, including senior notes due within one year. As of December 31, 2016, the Company did not have any outstanding secured debt.

Subsequent to December 31, 2016, the Company repaid at maturity $200 million aggregate principal amount of its Series 2007A 5.55% Senior Notes due February 1, 2017.

Redeemable Preferred and Preference Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized and outstanding. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary and involuntary dissolution. The preferred stock and Class A preferred stock of the Company contain a feature that allows the holders to elect a majority of the Company's board of directors if preferred dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of the Company, the preferred stock and Class A preferred stock is presented as "Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards. The preference stock does not contain such a provision that would allow the holders to elect a majority of the Company's board. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution.

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The Company's preferred stock is subject to redemption at a price equal to the par value plus a premium. The Company's Class A preferred stock is subject to redemption at a price equal to the stated capital. The Company's outstanding preference stock is subject to redemption at a price equal to the stated capital plus a make-whole premium based on the present value of the liquidation amount and future dividends to the first stated capital redemption date. All series of the Company's preferred stock currently are subject to redemption at the option of the Company. Information for each outstanding series is in the table below:

Preferred/Preference Stock	Par Value/Stated Capital Per Share	Shares Outstanding	Redemption Price Per Share
4.92% Preferred Stock	$100	80,000	$103.23
4.72% Preferred Stock	$100	50,000	$102.18
4.64% Preferred Stock	$100	60,000	$103.14
4.60% Preferred Stock	$100	100,000	$104.20
4.52% Preferred Stock	$100	50,000	$102.93
4.20% Preferred Stock	$100	135,115	$105.00
5.83% Class A Preferred Stock	$25	1,520,000	Stated Capital
6.45% Preference Stock	$25	6,000,000	Stated Capital (*)
6.50% Preference Stock	$25	2,000,000	Stated Capital (*)

(*) Also includes a make-whole premium prior to October 1, 2017

In May 2015, the Company redeemed 6.48 million shares ($162 million aggregate stated capital) of the Company's 5.20% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date and 4.0 million shares ($100 million aggregate stated capital) of the Company's 5.30% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date. Additionally, the $5 million of issuance costs were transferred from redeemable preferred stock to common stockholder's equity upon redemption. Also during May 2015, the Company redeemed 6.0 million shares ($150 million aggregate stated capital) of the Company's 5.625% Series Preference Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date. There were no changes for the years ended December 31, 2016 and 2014 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, 2016 , committed credit arrangements with banks were as follows:

Expires					Expires Within One Year	
2017	2018	2020	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 / 10 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

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

Most of the Company's bank credit arrangements contain covenants that limit the Company's debt 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, 2016 , 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 $890 million as of December 31, 2016 . In addition, at December 31, 2016, the Company had $87 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, 2016 and 2015 , there was no short-term debt outstanding. At December 31, 2016 , the Company had regulatory approval to have outstanding up to $2.1 billion of short-term borrowings.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2016, 2015, and 2014, the Company incurred fuel expense of $1.3 billion , $1.3 billion , and $1.6 billion , respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

In addition, the Company has entered into various long-term commitments for the purchase of capacity and electricity, some of which are accounted for as operating leases. Total capacity expense under PPAs accounted for as operating leases was $42 million , $38 million , and $37 million for 2016, 2015, and 2014, respectively. Total estimated minimum long-term obligations at December 31, 2016 were as follows:

	Operating Lease PPAs
	(in millions)
2017	$ 40
2018	41
2019	43
2020	44
2021	46
2022	47
Total commitments	$ 261

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 rental agreements for coal railcars, vehicles, and other equipment with various terms and expiration dates. Total rent expense under these agreements was $18 million in 2016 , $19 million in 2015 , and $18 million in 2014 . Of these amounts, $14 million , $13 million , and $14 million for 2016, 2015, and 2014, respectively, relate to the railcar leases and was recovered through the Company's Rate ECR. As of December 31, 2016, estimated minimum lease payments under operating leases were as follows:

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	Minimum Lease Payments		
	Railcars	Vehicles & Other	Total
		(in millions)	
2017	$ 10	$ 4	$ 14
2018	7	3	10
2019	7	3	10
2020	6	2	8
2021	6	2	8
2022 and thereafter	9	1	10
Total	$ 45	$ 15	$ 60

In addition to the above rental commitments payments, the Company has potential obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases have terms expiring through 2023 with maximum obligations under these leases of $12 million in 2023. There are no obligations under these leases through 2021. 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 may be granted through the Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2016 , there were 865 current and former employees participating in the stock option and performance share unit programs.

Stock Options

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

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

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

The total intrinsic value of options exercised during the years ended December 31, 2016 , 2015 , and 2014 was $21 million , $8 million , and $21 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 $8 million , $3 million , and $8 million for the years ended December 31, 2016 , 2015 , and 2014 , respectively. Prior to the adoption of ASU 2016-09, the excess tax benefits related to the exercise of stock options were recognized in the Company's financial statements with a credit to equity. Upon the adoption of ASU 2016-09, beginning in 2016, all tax benefits related to the exercise of stock options are recognized in income. As of December 31, 2016 , the aggregate intrinsic value for the options outstanding and options exercisable was $30 million and $26 million , respectively.

Performance Share Units

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

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

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

For the years ended December 31, 2016 , 2015 , and 2014, employees of the Company were granted performance share units of 249,065 , 214,709 , and 176,070 , respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2016, 2015, and 2014, determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $45.15 , $46.42 , and $37.54 , respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2016 and 2015 was $48.86 and $47.78 , respectively.

For the years ended December 31, 2016 , 2015 , and 2014, total compensation cost for performance share units recognized in income was $15 million , $13 million , and $5 million , respectively, with the related tax benefit also recognized in income of $6 million , $5 million , and $2 million , respectively. The compensation cost related to the grant of Southern Company performance share units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2016 , $3 million of total unrecognized

compensation cost related to performance share award units will be recognized over a weighted-average period of approximately 22 months .

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant 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 $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company is $255 million per incident but not more than an aggregate of $38 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years . The next scheduled adjustment is due no later than September 10, 2018.

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

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

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The maximum annual assessments for the Company as of December 31, 2016 under the NEIL policies would be $53 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.

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

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

	Fair Value Measurements Using				
As of December 31, 2016:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**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.

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

	Fair Value Measurements Using				
As of December 31, 2015:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Assets:					
Energy-related derivatives	$ —	$ 1	$ —	$ —	$ 1
Nuclear decommissioning trusts: (*)					
Domestic equity	359	68	—	—	427
Foreign equity	47	47	—	—	94
U.S. Treasury and government agency securities	—	27	—	—	27
Corporate bonds	11	135	—	—	146
Mortgage and asset backed securities	—	18	—	—	18
Private equity	—	—	—	17	17
Other	—	5	—	—	5
Cash equivalents	68	—	—	—	68
Total	$ 485	$ 301	$ —	$ 17	$ 803
Liabilities:					
Interest rate derivatives	$ —	$ 15	$ —	$ —	$ 15
Energy-related derivatives	—	55	—	—	55
Total	$ —	$ 70	$ —	$ —	$ 70

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

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, 2016 and 2015 , 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, 2016	**$ 20**	**$ 25**	**Not Applicable**	**Not Applicable**
As of December 31, 2015	$ 17	$ 28	Not Applicable	Not Applicable

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

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

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt, including securities due within one year:		
2016	**$ 7,092**	**$ 7,544**
2015	$ 6,849	$ 7,192

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, 2016 , the net volume of energy-related derivative contracts for natural gas positions totaled 74 million mmBtu for the Company, with the longest hedge date of 2020 over which it is hedging its exposure to the variability in future cash flows for forecasted transactions.

Interest Rate Derivatives

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

At December 31, 2016 , there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2017 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. At December 31, 2016 , fair value amounts of derivative assets and liabilities on the balance sheets are presented net to the extent that there are netting arrangements or similar agreements with the counterparties. At December 31, 2015 , the fair value amounts of derivative instruments were presented gross on the balance sheets.

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

	2016		2015	
Derivative Category and Balance Sheet Location	**Assets**	**Liabilities**	Assets	Liabilities
		(in millions)		
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Other current liabilities	**$ 13**	**$ 5**	$ 1	$ 40
Other deferred charges and assets/Other deferred credits and liabilities	**7**	**4**	—	15
Total derivatives designated as hedging instruments for regulatory purposes	**$ 20**	**$ 9**	$ 1	$ 55
Derivatives designated as hedging instruments in cash flow hedges				
Interest rate derivatives:				
Other current assets/Other current liabilities	**$ —**	**$ —**	$ —	$ 15
Gross amounts recognized	**$ 20**	**$ 9**	$ 1	$ 70
Gross amounts offset	**$ (8)**	**$ (8)**	$ (1)	$ (1)
Net amounts recognized in the Balance Sheets (*)	**$ 12**	**$ 1**	$ —	$ 69

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

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

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At December 31, 2016 and 2015 , 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**	**2016**	2015	**Balance Sheet Location**	**2016**	2015
		(in millions)			*(in millions)*	
Energy-related derivatives: (*)	Other regulatory assets, current	**$ (1)**	$ (40)	Other current liabilities	**$ 8**	$ 1
	Other regulatory assets, deferred	**—**	(15)	Other regulatory liabilities, deferred	**4**	—
Total energy-related derivative gains (losses)		**$ (1)**	$ (55)		**$ 12**	$ 1

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

For the years ended December 31, 2016 , 2015 , and 2014 , 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	**2016**	2015	2014	**Statements of Income Location**	**2016**	2015	2014
		(in millions)				*(in millions)*	
Interest rate derivatives	**$ (3)**	$ (7)	$ (8)	Interest expense, net of amounts capitalized	**$ (6)**	$ (3)	$ (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, 2016 , the fair value of derivative liabilities with contingent features, including certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade because of joint and several liability features underlying these derivatives, was immaterial.

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

The Company 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, 2016 , 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.

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12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

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

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2016	**$ 1,331**	**$ 333**	**$ 156**
June 2016	**1,444**	**430**	**213**
September 2016	**1,785**	**650**	**351**
December 2016	**1,329**	**252**	**102**
March 2015	$ 1,401	$ 346	$ 169
June 2015	1,455	398	200
September 2015	1,695	555	295
December 2015	1,217	264	121

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

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

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

	2016	2015	2014	2013	2012
Operating Revenues (in millions)	**$ 5,889**	$ 5,768	$ 5,942	$ 5,618	$ 5,520
Net Income After Dividends on Preferred and Preference Stock (in millions)	**$ 822**	$ 785	$ 761	$ 712	$ 704
Cash Dividends on Common Stock (in millions)	**$ 765**	$ 571	$ 550	$ 644	$ 684
Return on Average Common Equity (percent)	**13.34**	13.37	13.52	13.07	13.10
Total Assets (in millions) (a)(b)	**$ 22,516**	$ 21,721	$ 20,493	$ 19,185	$ 18,647
Gross Property Additions (in millions)	**$ 1,338**	$ 1,492	$ 1,543	$ 1,204	$ 940
Capitalization (in millions):					
Common stock equity	**$ 6,323**	$ 5,992	$ 5,752	$ 5,502	$ 5,398
Preference stock	**196**	196	343	343	343
Redeemable preferred stock	**85**	85	342	342	342
Long-term debt (a)	**6,535**	6,654	6,137	6,195	5,890
Total (excluding amounts due within one year)	**$ 13,139**	$ 12,927	$ 12,574	$ 12,382	$ 11,973
Capitalization Ratios (percent):					
Common stock equity	**48.1**	46.4	45.8	44.4	45.1
Preference stock	**1.5**	1.5	2.7	2.8	2.9
Redeemable preferred stock	**0.7**	0.7	2.7	2.7	2.9
Long-term debt (a)	**49.7**	51.4	48.8	50.1	49.1
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**1,262,752**	1,253,875	1,247,061	1,241,998	1,237,730
Commercial	**199,146**	197,920	197,082	196,209	196,177
Industrial	**6,090**	6,056	6,032	5,851	5,839
Other	**762**	757	753	751	748
Total	**1,468,750**	1,458,608	1,450,928	1,444,809	1,440,494
Employees (year-end)	**6,805**	6,986	6,935	6,896	6,778

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $40 million, $38 million, and $39 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(b) A reclassification of deferred tax assets from Total Assets of $20 million, $27 million, and $27 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

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

	2016	2015	2014	2013	2012
Operating Revenues (in millions):					
Residential	$ 2,322	$ 2,207	$ 2,209	$ 2,079	$ 2,068
Commercial	1,627	1,564	1,533	1,477	1,491
Industrial	1,416	1,436	1,480	1,369	1,346
Other	(43)	27	27	27	28
Total retail	5,322	5,234	5,249	4,952	4,933
Wholesale — non-affiliates	283	241	281	248	277
Wholesale — affiliates	69	84	189	212	111
Total revenues from sales of electricity	5,674	5,559	5,719	5,412	5,321
Other revenues	215	209	223	206	199
Total	$ 5,889	$ 5,768	$ 5,942	$ 5,618	$ 5,520
Kilowatt-Hour Sales (in millions):					
Residential	18,343	18,082	18,726	17,920	17,612
Commercial	14,091	14,102	14,118	13,892	13,963
Industrial	22,310	23,380	23,799	22,904	22,158
Other	208	201	211	211	214
Total retail	54,952	55,765	56,854	54,927	53,947
Wholesale — non-affiliates	3,597	3,567	3,588	3,711	4,196
Wholesale — affiliates	5,324	4,515	6,713	7,672	4,279
Total	63,873	63,847	67,155	66,310	62,422
Average Revenue Per Kilowatt-Hour (cents):					
Residential	12.66	12.21	11.80	11.60	11.74
Commercial	11.55	11.09	10.86	10.63	10.68
Industrial	6.35	6.14	6.22	5.98	6.07
Total retail	9.68	9.39	9.23	9.02	9.14
Wholesale	3.95	4.02	4.56	4.04	4.58
Total sales	8.88	8.71	8.52	8.16	8.52
Residential Average Annual Kilowatt-Hour Use Per Customer	14,568	14,454	15,051	14,451	14,252
Residential Average Annual Revenue Per Customer	$ 1,844	$ 1,764	$ 1,775	$ 1,676	$ 1,674
Plant Nameplate Capacity Ratings (year-end) (megawatts)	11,797	11,797	12,222	12,222	12,222
Maximum Peak-Hour Demand (megawatts):					
Winter	10,282	12,162	11,761	9,347	10,285
Summer	10,932	11,292	11,054	10,692	11,096
Annual Load Factor (percent)	63.5	58.4	61.4	64.9	61.3
Plant Availability (percent):					
Fossil-steam	83.0	81.5	82.5	87.3	88.6
Nuclear	88.0	92.1	93.3	90.7	94.5
Source of Energy Supply (percent):					
Coal	47.1	49.1	49.0	50.0	48.2
Nuclear	20.3	21.3	20.7	20.3	22.6
Hydro	4.8	5.6	5.5	8.1	4.1
Gas	17.1	14.6	15.4	15.7	16.8
Purchased power —					
From non-affiliates	4.8	4.4	3.6	2.9	2.0
From affiliates	5.9	5.0	5.8	3.0	6.3
Total	100.0	100.0	100.0	100.0	100.0

GEORGIA POWER COMPANY

FINANCIAL SECTION

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

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

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

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

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

February 21, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Georgia Power Company

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2016 and 2015 , and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2016 . These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such financial statements (pages II-263 to II-310) present fairly, in all material respects, the financial position of Georgia Power Company as of December 31, 2016 and 2015 , and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016 , in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 21, 2017

DEFINITIONS

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

DEFINITIONS
(continued)

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

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

OVERVIEW

Business Activities

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

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

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

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

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

Earnings

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

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

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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2016 Annual Report

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

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

Operating Revenues

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

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

Retail base revenues of $5.6 billion in 2016 increased $256 million, or 4.8%, compared to 2015 . The significant factors driving this change are shown in the preceding table. The increase in rates and pricing was primarily due to increases in base tariffs approved under the 2013 ARP and the NCCR tariff, all effective January 1, 2016. Also contributing to the increase was the 2015 correction of an error affecting billings since 2013 to a small number of large commercial and industrial customers under a rate

plan allowing for variable demand-driven pricing. The increase was partially offset by an adjustment for an expected refund to retail customers as a result of the Company's retail ROE exceeding the allowed retail ROE range under the 2013 ARP during 2016. In 2016 , residential base revenues increased $152 million, or 6.3%, commercial base revenues increased $65 million, or 3.0%, and industrial base revenues increased $39 million, or 5.6%, compared to 2015 .

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

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

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

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

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

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

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

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

Other operating revenues increased $30 million , or 8.2% , in 2016 from the prior year primarily due to a $14 million increase related to customer temporary facilities services revenues and a $12 million increase in outdoor lighting revenues due to increased sales in new and replacement markets, primarily attributable to conversions from traditional to LED lighting. Other operating revenues decreased $7 million, or 1.9%, in 2015 from the prior year primarily due to a $16 million decrease in transmission

service revenues primarily as a result of a contract that expired in December 2014, partially offset by an $11 million increase in outdoor lighting revenues .

Energy Sales

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

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

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

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

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

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

Fuel and Purchased Power Expenses

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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2016 Annual Report

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

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

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

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

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

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

Fuel

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

Purchased Power - Non-Affiliates

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

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

Purchased Power - Affiliates

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

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

Other Operations and Maintenance Expenses

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

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

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

Depreciation and Amortization

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

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

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

Taxes Other Than Income Taxes

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

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

Interest Expense, Net of Amounts Capitalized

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

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

Other Income (Expense), Net

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

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

Income Taxes

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

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

Effects of Inflation

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

FUTURE EARNINGS POTENTIAL

General

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

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

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are completed. The Company's Environmental Compliance Cost Recovery (ECCR) tariff allows for the recovery of capital and operations and maintenance costs related to environmental controls mandated by state and federal

regulations. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

Environmental Statutes and Regulations

General

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

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations, including the environmental regulations described below; the time periods over which compliance with regulations is required; individual state implementation of regulations, as applicable; the outcome of any legal challenges to the environmental rules; any additional rulemaking activities in response to legal challenges and court decisions; the cost, availability, and existing inventory of emissions allowances; the impact of future changes in generation and emissions-related technology; the Company's fuel mix; and environmental remediation requirements. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time.

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

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company.

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

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

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

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

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

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

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

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

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

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

Water Quality

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

In November 2015, the EPA published a final effluent guidelines rule which imposes stringent technology-based requirements for certain wastestreams from steam electric power plants. The revised technology-based limits and compliance dates will be

incorporated into future renewals of NPDES permits at affected units and may require the installation and operation of multiple technologies sufficient to ensure compliance with applicable new numeric wastewater compliance limits. Compliance deadlines between November 1, 2018 and December 31, 2023 will be established in permits based on information provided for each applicable wastestream.

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

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

Coal Combustion Residuals

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

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

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

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

Environmental Remediation

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

Global Climate Issues

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

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

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

The EPA's greenhouse gas reporting rule requires annual reporting of greenhouse gas emissions expressed in terms of metric tons of CO_2 equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2015 greenhouse gas emissions were approximately 32 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2016 greenhouse gas emissions on the same basis is approximately 33 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation, the mix of fuel sources, and other factors.

FERC Matters

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

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

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

Retail Regulatory Matters

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

Rate Plans

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

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

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

Renewables

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

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

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

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

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

Integrated Resource Plan

See "Environmental Matters" herein for additional information regarding proposed and final EPA rules and regulations, including the MATS rule for coal- and oil-fired electric utility steam generating units, revisions to effluent limitations guidelines for steam

electric power plants, and additional regulations of CCR and CO_2; and the Company's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations.

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

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

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

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

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

Fuel Cost Recovery

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

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

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

Storm Damage Recovery

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

Nuclear Construction

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

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

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

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

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

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

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

requested in the February 2015 filing unnecessary and withdrawn until the completion of construction of Plant Vogtle Unit 3 consistent with the 2013 Stipulation.

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

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

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

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

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

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

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

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

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

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

Income Tax Matters

Bonus Depreciation

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

Other Matters

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

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

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

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Utility Regulation

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

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

Asset Retirement Obligations

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

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

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

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

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

Pension and Other Postretirement Benefits

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

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

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

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

Contingent Obligations

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

Recently Issued Accounting Standards

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers,* replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to

customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

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

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

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

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

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

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

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2016. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to build new generation facilities, including Plant Vogtle Units 3 and 4, to maintain

existing generation facilities, to comply with environmental regulations including adding environmental modifications to existing generating units, to expand and improve transmission and distribution facilities, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2017 through 2019, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Company plans to finance future cash needs in excess of its operating cash flows primarily through securities issuances, capital contributions from Southern Company, borrowings from financial institutions, and borrowings through the FFB. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

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

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

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

Net cash used for financing activities totaled $142 million , $530 million , and $163 million for 2016, 2015, and 2014, respectively. The decrease in cash used in 2016 compared to 2015 was primarily due to higher capital contributions from Southern Company, a decrease in redemptions and maturities of senior notes, and an increase in short-term debt, partially offset by higher common stock dividends and a decrease in borrowings from the FFB for construction of Plant Vogtle Units 3 and 4. The increase in cash used in 2015 compared to 2014 was primarily due to the redemption and maturity of senior notes in 2015. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2016 included an increase in property, plant, and equipment of $1.6 billion to comply with environmental standards and construction of generation, transmission, and distribution facilities, increases in other regulatory assets, deferred of $622 million and current and deferred ARO liabilities of $616 million primarily related to changes in ash pond closure strategy, an increase of $373 million in accumulated deferred income taxes primarily as a result of bonus depreciation, and an increase of $357 million in long-term debt due to issuances exceeding maturities. See Note 1 to the financial statements for additional information.

The Company's ratio of common equity to total capitalization plus short-term debt, was 50.0% at December 31, 2016 and 49.9% at December 31, 2015. See Note 6 to the financial statements for additional information.

Sources of Capital

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

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

financial statements under "Retail Regulatory Matters – Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

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

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

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

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

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

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

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

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

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

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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Details of short-term borrowings were as follows:

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

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

The Company believes the need for working capital can be adequately met by utilizing the commercial paper program, lines of credit, short-term bank notes, and operating cash flows.

Financing Activities

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Senior Notes

In March 2016, the Company issued $325 million aggregate principal amount of Series 2016A 3.25% Senior Notes due April 1, 2026 and $325 million aggregate principal amount of Series 2016B 2.40% Senior Notes due April 1, 2021. An amount equal to the proceeds from the Series 2016A 3.25% Senior Notes due April 1, 2026 is being allocated to eligible green expenditures, including financing of or investments in solar generating facilities or electric vehicle charging infrastructure, or payments under PPAs served by solar or wind generating facilities. The proceeds from the Series 2016B 2.40% Senior Notes due April 1, 2021 were used to repay at maturity $250 million aggregate principal amount of the Company's Series 2013B Floating Rate Senior Notes due March 15, 2016, to repay a portion of the Company's short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

In April 2016, the Company's $250 million aggregate principal amount of Series 2011B 3.00% Senior Notes were repaid at maturity.

In August 2016, the Company's $200 million aggregate principal amount of Series 2013C Floating Rate Senior Notes were repaid at maturity.

Pollution Control Revenue Bonds

In January 2016, $4.085 million aggregate principal amount of Savannah Economic Development Authority Pollution Control Revenue Bonds (Savannah Electric and Power Company Project), First Series 1993 were repaid at maturity.

DOE Loan Guarantee Borrowings

In June and December 2016, the Company made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $300 million and $125 million, respectively. The interest rate applicable to the $300 million principal amount is 2.571% and the interest rate applicable to the $125 million principal amount is 3.142%, both for interest periods that extend to the final maturity date of February 20, 2044. The proceeds were used to reimburse the Company for Eligible Project Costs relating to the construction of Plant Vogtle Units 3 and 4.

Under the Loan Guarantee Agreement, the Company is subject to customary events of default, as well as cross-defaults to other indebtedness and events of default relating to any failure to make payments under the engineering, procurement, and construction contract, as amended, relating to Plant Vogtle Units 3 and 4 or certain other agreements providing intellectual property rights for Plant Vogtle Units 3 and 4. The Loan Guarantee Agreement also includes events of default specific to the DOE loan guarantee program, including the failure of the Company or Southern Nuclear to comply with requirements of law or DOE loan guarantee program requirements. In the event certain mandatory prepayment events occur, the FFB's commitment to make further advances under the FFB Credit Facility will terminate and the Company will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facility over a period of five years (with level principal amortization). See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information.

Credit Rating Risk

At December 31, 2016, the Company did not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, transmission, and construction of new generation at Plant Vogtle Units 3 and 4.

The maximum potential collateral requirements under these contracts at December 31, 2016 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 93
Below BBB- and/or Baa3	$ 1,258

Included in these amounts are certain agreements that could require collateral in the event that the Company or Alabama Power has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of the Company to access capital markets and would be likely to impact the cost at which it does so.

On January 10, 2017, S&P revised its consolidated credit rating outlook for Southern Company (including the Company) from negative to stable.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives designated as hedges. The weighted average interest rate on $1.8 billion of long-term variable interest rate exposure at January 1, 2017 was 1.91%. If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $18 million at January 1, 2017. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The Company continues to manage a fuel-hedging program implemented per the guidelines of the Georgia PSC. The Company had no material change in market risk exposure for the year ended December 31, 2016 when compared to the December 31, 2015 reporting period.

The changes in fair value of energy-related derivative contracts are substantially attributable to both the volume and the price of natural gas. For the years ended December 31, the changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, were as follows:

	2016 Changes	2015 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (13)**	$ (20)
Contracts realized or settled:		
Swaps realized or settled	**(2)**	2
Options realized or settled	**11**	18
Current period changes (*) :		
Swaps	**31**	—
Options	**9**	(13)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ 36**	$ (13)

(*) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The net hedge volumes of energy-related derivative contracts for the years ended December 31 were as follows:

	2016	2015
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	**128**	—
Commodity – Natural gas options	**27**	50
Total hedge volume	**155**	50

The weighted average swap contract cost below market prices was approximately $0.23 per mmBtu as of December 31, 2016. There were no swaps outstanding as of December 31, 2015. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. All natural gas hedge gains and losses are recovered through the Company's fuel cost recovery mechanism.

At December 31, 2016 and 2015, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Through December 31, 2015, the Company's fuel-hedging program had a time horizon up to 24 months. Effective January 1, 2016, the Georgia PSC approved changes to the Company's hedging program allowing it to use an array of derivative instruments within a 48-month time horizon. Hedging gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery mechanism. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2 of the fair value hierarchy. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2016 were as follows:

	Fair Value Measurements December 31, 2016		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
	(in millions)		
Level 1	$ —	$ —	$ —
Level 2	36	28	8
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ 36	$ 28	$ 8

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related and interest rate derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to total $2.6 billion for 2017, $2.7 billion for 2018, $2.1 billion for 2019, $1.9 billion for 2020, and $1.7 billion for 2021. These amounts include expenditures of approximately $0.7 billion, $0.5 billion, $0.3 billion, and $0.1 billion for the construction of Plant Vogtle Units 3 and 4 in 2017, 2018, 2019, and 2020, respectively. These amounts also include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these amounts are $0.4 billion , $0.3 billion , $0.1 billion , $0.2 billion , and $0.2 billion for 2017, 2018, 2019, 2020, and 2021, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from new, existing, modified, or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and "– Global Climate Issues" herein for additional information.

The Company also anticipates costs associated with closure and monitoring of ash ponds in accordance with the CCR Rule, which are reflected in the Company's ARO liabilities. These costs, which could change as the Company continues to refine its assumptions underlying the cost estimates and evaluate the method and timing of compliance activities, are estimated to be $0.3 billion for 2017 and $0.2 billion per year for 2018 through 2021. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing generating units, to meet regulatory requirements; changes in FERC rules and regulations; Georgia PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for information regarding additional factors that may impact construction expenditures.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Georgia PSC and the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, other purchase commitments, and trusts are

detailed in the contractual obligations table that follows. See Notes 1, 2, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

Contractual obligations at December 31, 2016 were as follows:

	2017	2018-2019	2020-2021	After 2021	Total
			(in millions)		
Long-term debt [(a)] —					
Principal	$ 450	$ 1,250	$ 413	$ 8,533	$ 10,646
Interest	383	698	628	5,112	6,821
Preferred and preference stock dividends [(b)]	17	35	35	—	87
Financial derivative obligations [(c)]	1	6	1	—	8
Operating leases [(d)]	19	22	17	15	73
Capital leases [(d)]	9	17	7	—	33
Purchase commitments —					
Capital [(e)]	2,412	4,347	2,941	—	9,700
Fuel [(f)]	1,628	1,681	878	6,320	10,507
Purchased power [(g)]	320	595	539	2,543	3,997
Other [(h)]	108	141	126	361	736
Trusts —					
Nuclear decommissioning [(i)]	5	11	11	99	126
Pension and other postretirement benefit plans [(j)]	46	90	—	—	136
Total	$ 5,398	$ 8,893	$ 5,596	$ 22,983	$ 42,870

(a) All amounts are reflected based on final maturity dates except for amounts related to FFB borrowings. As it relates to the FFB borrowings, the final maturity date is February 20, 2044; however, principal amortization is reflected beginning in 2020. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2017, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).
(b) Preferred and preference stock do not mature; therefore, amounts provided are for the next five years only.
(c) Includes derivative liabilities related to energy-related derivatives. For additional information, see Notes 1 and 11 to the financial statements.
(d) Excludes PPAs that are accounted for as leases and included in "Purchased power."
(e) The Company provides estimated capital expenditures for a five-year period, including capital expenditures associated with environmental regulations. These amounts exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements which are reflected in "Fuel" and "Other," respectively. At December 31, 2016, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and "Retail Regulatory Matters – Nuclear Construction" herein for additional information.
(f) Includes commitments to purchase coal, nuclear fuel, and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2016.
(g) Estimated minimum long-term obligations for various PPA purchases from gas-fired, biomass, and wind-powered facilities. Includes a total of $292 million of biomass PPAs that is contingent upon the counterparties meeting specified contract dates for commercial operation. Subsequent to December 31, 2016, the specified contract dates for commercial operation were extended from 2017 to 2019 and may change further as a result of regulatory action. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Renewables" herein for additional information.
(h) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices.
(i) Projections of nuclear decommissioning trust fund contributions for Plant Hatch and Plant Vogtle Units 1 and 2 are based on the 2013 ARP . See Note 1 to the financial statements under "Nuclear Decommissioning" for additional information.
(j) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2016 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning regulated rates, customer and sales growth, economic conditions, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan , postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, completion dates of construction projects, filings with state and federal regulatory authorities, impact of the PATH Act, federal income tax benefits, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws regulating emissions, discharges, and disposal to air, water, and land , and also changes in tax and other laws and regulations to which the Company is subject, including potential tax reform legislation, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries ;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development , construction, and operation of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed;
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any environmental performance standards and the requirements of tax credits and other incentives , and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of the Company's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate cases related to fuel and other cost recovery mechanisms;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;

- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general , as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of the Company to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

STATEMENTS OF INCOME
For the Years Ended December 31, 2016 , 2015 , and 2014
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	2016	2015	2014
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 7,772**	$ 7,727	$ 8,240
Wholesale revenues, non-affiliates	**175**	215	335
Wholesale revenues, affiliates	**42**	20	42
Other revenues	**394**	364	371
Total operating revenues	**8,383**	8,326	8,988
Operating Expenses:			
Fuel	**1,807**	2,033	2,547
Purchased power, non-affiliates	**361**	289	287
Purchased power, affiliates	**518**	575	701
Other operations and maintenance	**1,960**	1,844	1,902
Depreciation and amortization	**855**	846	846
Taxes other than income taxes	**405**	391	409
Total operating expenses	**5,906**	5,978	6,692
Operating Income	**2,477**	2,348	2,296
Other Income and (Expense):			
Interest expense, net of amounts capitalized	**(388)**	(363)	(348)
Other income (expense), net	**38**	61	23
Total other income and (expense)	**(350)**	(302)	(325)
Earnings Before Income Taxes	**2,127**	2,046	1,971
Income taxes	**780**	769	729
Net Income	**1,347**	1,277	1,242
Dividends on Preferred and Preference Stock	**17**	17	17
Net Income After Dividends on Preferred and Preference Stock	**$ 1,330**	$ 1,260	$ 1,225

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2016 , 2015 , and 2014
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	2016	2015	2014
		(in millions)	
Net Income	**$ 1,347**	$ 1,277	$ 1,242
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $(6), and $(3), respectively	—	(9)	(5)
Reclassification adjustment for amounts included in net income, net of tax of $2, $1, and $1, respectively	**2**	2	2
Total other comprehensive income (loss)	**2**	(7)	(3)
Comprehensive Income	**$ 1,349**	$ 1,270	$ 1,239

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2016 , 2015 , and 2014
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	2016	2015	2014
		(in millions)	
Operating Activities:			
Net income	**$ 1,347**	$ 1,277	$ 1,242
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**1,063**	1,029	1,019
Deferred income taxes	**383**	173	352
Allowance for equity funds used during construction	**(48)**	(40)	(45)
Retail fuel cost over-recovery — long-term	**—**	106	(44)
Pension and postretirement funding	**(287)**	(7)	(156)
Settlement of asset retirement obligations	**(123)**	(29)	(12)
Other deferred charges — affiliated	**(111)**	—	—
Other, net	**(10)**	10	70
Changes in certain current assets and liabilities —			
-Receivables	**60**	187	(248)
-Fossil fuel stock	**104**	37	303
-Prepaid income taxes	**—**	89	(216)
-Other current assets	**(38)**	(62)	(37)
-Accounts payable	**(42)**	(259)	16
-Accrued taxes	**131**	25	17
-Accrued compensation	**(5)**	(17)	62
-Other current liabilities	**1**	(2)	40
Net cash provided from operating activities	**2,425**	2,517	2,363
Investing Activities:			
Property additions	**(2,223)**	(2,091)	(2,023)
Nuclear decommissioning trust fund purchases	**(808)**	(985)	(671)
Nuclear decommissioning trust fund sales	**803**	980	669
Cost of removal, net of salvage	**(83)**	(71)	(65)
Change in construction payables, net of joint owner portion	**(35)**	217	(54)
Prepaid long-term service agreements	**(34)**	(66)	(70)
Sale of property	**10**	70	7
Other investing activities	**23**	2	1
Net cash used for investing activities	**(2,347)**	(1,944)	(2,206)
Financing Activities:			
Increase (decrease) in notes payable, net	**234**	2	(891)
Proceeds —			
Senior notes	**650**	500	—
FFB loan	**425**	1,000	1,200
Pollution control revenue bonds issuances and remarketings	**—**	409	40
Capital contributions from parent company	**594**	62	549
Short-term borrowings	**—**	250	—
Redemptions and repurchases —			
Senior notes	**(700)**	(1,175)	—
Pollution control revenue bonds	**(4)**	(268)	(37)
Short-term borrowings	**—**	(250)	—
Payment of common stock dividends	**(1,305)**	(1,034)	(954)
Other financing activities	**(36)**	(26)	(70)
Net cash used for financing activities	**(142)**	(530)	(163)
Net Change in Cash and Cash Equivalents	**(64)**	43	(6)
Cash and Cash Equivalents at Beginning of Year	**67**	24	30

Cash and Cash Equivalents at End of Year	**$ 3**	$ 67	$ 24
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $20, $16, and $18 capitalized, respectively)	**$ 375**	$ 353	$ 319
Income taxes (net of refunds)	**170**	506	507
Noncash transactions —			
Accrued property additions at year-end	**336**	387	154
Capital lease obligation	**—**	149	—

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2016 and 2015
Georgia Power Company 2016 Annual Report

Assets		**2016**		2015
		(in millions)		
Current Assets:				
Cash and cash equivalents	**$**	**3**	$	67
Receivables —				
Customer accounts receivable		**523**		541
Unbilled revenues		**224**		188
Joint owner accounts receivable		**57**		227
Income taxes receivable, current		**—**		114
Other accounts and notes receivable		**81**		57
Affiliated		**18**		18
Accumulated provision for uncollectible accounts		**(3)**		(2)
Fossil fuel stock		**298**		402
Materials and supplies		**479**		449
Prepaid expenses		**105**		230
Other regulatory assets, current		**193**		213
Other current assets		**38**		19
Total current assets		**2,016**		2,523
Property, Plant, and Equipment:				
In service		**33,841**		31,841
Less accumulated provision for depreciation		**11,317**		10,903
Plant in service, net of depreciation		**22,524**		20,938
Other utility plant, net		**—**		171
Nuclear fuel, at amortized cost		**569**		572
Construction work in progress		**4,939**		4,775
Total property, plant, and equipment		**28,032**		26,456
Other Property and Investments:				
Equity investments in unconsolidated subsidiaries		**60**		64
Nuclear decommissioning trusts, at fair value		**814**		775
Miscellaneous property and investments		**46**		43
Total other property and investments		**920**		882
Deferred Charges and Other Assets:				
Deferred charges related to income taxes		**676**		679
Other regulatory assets, deferred		**2,774**		2,152
Other deferred charges and assets		**417**		173
Total deferred charges and other assets		**3,867**		3,004
Total Assets	**$**	**34,835**	$	32,865

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2016 and 2015
Georgia Power Company 2016 Annual Report

Liabilities and Stockholder's Equity	**2016**	2015
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 460**	$ 712
Notes payable	**391**	158
Accounts payable —		
Affiliated	**438**	411
Other	**589**	750
Customer deposits	**265**	264
Accrued taxes —		
Accrued income taxes	**17**	12
Other accrued taxes	**390**	325
Accrued interest	**106**	99
Accrued compensation	**224**	205
Asset retirement obligations, current	**299**	179
Other regulatory liabilities, current	**31**	16
Over recovered regulatory clause revenues, current	**84**	10
Other current liabilities	**182**	154
Total current liabilities	**3,476**	3,295
Long-Term Debt (See accompanying statements)	**10,225**	9,616
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**6,000**	5,627
Deferred credits related to income taxes	**121**	105
Accumulated deferred investment tax credits	**256**	204
Employee benefit obligations	**703**	949
Asset retirement obligations, deferred	**2,233**	1,737
Other deferred credits and liabilities	**199**	347
Total deferred credits and other liabilities	**9,512**	8,969
Total Liabilities	**23,213**	21,880
Preferred Stock (See accompanying statements)	**45**	45
Preference Stock (See accompanying statements)	**221**	221
Common Stockholder's Equity (See accompanying statements)	**11,356**	10,719
Total Liabilities and Stockholder's Equity	**$ 34,835**	$ 32,865
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CAPITALIZATION
At December 31, 2016 and 2015
Georgia Power Company 2016 Annual Report

	2016	2015	2016	2015
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
Variable rates (0.76% to 0.83% at 1/1/16) due 2016	$ —	$ 450		
3.00% due 2016	—	250		
5.70% due 2017	**450**	450		
1.95% to 5.40% due 2018	**748**	747		
4.25% due 2019	**500**	502		
2.40% due 2021	**325**	—		
2.85% to 5.95% due 2022-2043	**4,175**	3,850		
Total long-term notes payable	**6,198**	6,249		
Other long-term debt —				
Pollution control revenue bonds —				
1.38% to 4.00% due 2022-2049	**952**	952		
Variable rate (0.22% at 1/1/16) due 2016	—	4		
Variable rates (0.77% to 0.87% at 1/1/17) due 2022-2053	**868**	868		
FFB loans —				
2.57% to 3.86% due 2020	**44**	37		
2.57% to 3.86% due 2021	**44**	37		
2.57% to 3.86% due 2022-2044	**2,537**	2,126		
Total other long-term debt	**4,445**	4,024		
Capitalized lease obligations	**169**	183		
Unamortized debt premium (discount), net	**(10)**	(10)		
Unamortized debt issuance expense	**(117)**	(118)		
Total long-term debt (annual interest requirement — $402 million)	**10,685**	10,328		
Less amount due within one year	**460**	712		
Long-term debt excluding amount due within one year	**10,225**	9,616	**46.8%**	46.7%
Preferred and Preference Stock:				
Non-cumulative preferred stock				
$25 par value — 6.125%				
Authorized — 50,000,000 shares				
Outstanding — 1,800,000 shares	**45**	45		
Non-cumulative preference stock				
$100 par value — 6.50%				
Authorized — 15,000,000 shares				
Outstanding — 2,250,000 shares	**221**	221		
Total preferred and preference stock (annual dividend requirement — $17 million)	**266**	266	**1.2**	1.3
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 20,000,000 shares				
Outstanding — 9,261,500 shares	**398**	398		
Paid-in capital	**6,885**	6,275		
Retained earnings	**4,086**	4,061		
Accumulated other comprehensive loss	**(13)**	(15)		
Total common stockholder's equity	**11,356**	10,719	**52.0**	52.0
Total Capitalization	**$ 21,847**	$ 20,601	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2016 , 2015 , and 2014
Georgia Power Company 2016 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
				(in millions)		
Balance at December 31, 2013	9	$ 398	$ 5,633	$ 3,565	$ (5)	$ 9,591
Net income after dividends on preferred and preference stock	—	—	—	1,225	—	1,225
Capital contributions from parent company	—	—	563	—	—	563
Other comprehensive income (loss)	—	—	—	—	(3)	(3)
Cash dividends on common stock	—	—	—	(954)	—	(954)
Other	—	—	—	(1)	—	(1)
Balance at December 31, 2014	9	398	6,196	3,835	(8)	10,421
Net income after dividends on preferred and preference stock	—	—	—	1,260	—	1,260
Capital contributions from parent company	—	—	79	—	—	79
Other comprehensive income (loss)	—	—	—	—	(7)	(7)
Cash dividends on common stock	—	—	—	(1,034)	—	(1,034)
Balance at December 31, 2015	**9**	**398**	**6,275**	**4,061**	**(15)**	**10,719**
Net income after dividends on preferred and preference stock	**—**	**—**	**—**	**1,330**	**—**	**1,330**
Capital contributions from parent company	**—**	**—**	**610**	**—**	**—**	**610**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**2**	**2**
Cash dividends on common stock	**—**	**—**	**—**	**(1,305)**	**—**	**(1,305)**
Balance at December 31, 2016	**9**	**$ 398**	**$ 6,885**	**$ 4,086**	**$ (13)**	**$ 11,356**

The accompanying notes are an integral part of these financial statements.

NOTES TO FINANCIAL STATEMENTS
Georgia Power Company 2016 Annual Report

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (the Company) is a wholly-owned subsidiary of Southern Company, which is the parent company of the Company and three other traditional electric operating companies, as well as Southern Power, Southern Company Gas (as of July 1, 2016), SCS, Southern LINC, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure, Inc. (PowerSecure) (as of May 9, 2016), and other direct and indirect subsidiaries. The traditional electric operating companies – the Company, Alabama Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electric service to retail customers within its traditional service territory located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern LINC provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and for other electric services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants, including the Company's Plant Hatch and Plant Vogtle. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.

The equity method is used for subsidiaries in which the Company has significant influence but does not control.

The Company is subject to regulation by the FERC and the Georgia PSC. As such, the Company's financial statements reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

In June 2015, the Company identified an error affecting the billing to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing from January 1, 2013 to June 30, 2015. In the second quarter 2015, the Company recorded an out of period adjustment of approximately $75 million to decrease retail revenues, resulting in a decrease to net income of approximately $47 million . The Company evaluated the effects of this error on the interim and annual periods that included the billing error. Based on an analysis of qualitative and quantitative factors, the Company determined the error was not material to any affected period and, therefore, an amendment of previously filed financial statements was not required.

Recently Issued Accounting Standards

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers,* replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

While the Company expects most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of such arrangements. The majority of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term. For such arrangements, the Company generally expects that the revenue from contracts with these customers will continue to be equivalent to the electricity supplied and billed in that period (including unbilled revenues) and the adoption of ASC 606 will not result in a significant shift in the timing of revenue recognition for such sales.

The Company's ongoing evaluation of other revenue streams and related contracts includes longer term contractual commitments and unregulated sales to customers. Some revenue arrangements, such as certain PPAs and alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on the Company's financial statements. In addition, the power and utilities industry is currently addressing other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). If final implementation guidance indicates CIAC will be accounted for under ASC 606 and offsetting regulatory treatment is not permitted, it is expected to have a material impact on the Company's financial statements.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. The Company must select a transition method to be applied either retrospectively to each prior reporting period presented or retrospectively with a cumulative effect adjustment to retained earnings at the date of initial adoption. As the ultimate impact of the new standard has not yet been determined, the Company has not elected its transition method.

On February 25, 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged . ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company is currently evaluating the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

On March 30, 2016, the FASB issued ASU No. 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5, 8, and 12 for disclosures impacted by ASU 2016-09.

On October 24, 2016, the FASB issued ASU No. 2016-16, *Income Taxes (Topic 740), Intra-Entity Transfers of Assets Other Than Inventory* (ASU 2016-16). Current GAAP prohibits the recognition of current and deferred income taxes for an affiliate asset transfer until the asset has been sold to an outside party. ASU 2016-16 requires an entity to recognize the income tax consequences of an affiliate transfer of an asset other than inventory when the transfer occurs. ASU 2016-16 is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. The amendments will be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The Company is currently assessing the impact of the standard on its financial statements and has not yet determined its ultimate impact.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Costs for these services amounted to $606 million , $585 million , and $555 million in 2016 , 2015 , and 2014 , respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services; general operations, management, and technical services; administrative services including procurement, accounting, employee relations, systems, and procedures services; strategic planning and budgeting services; and other services with respect to business, operations, and construction management. Costs for these services amounted to $666 million , $681 million , and $643 million in 2016 , 2015 , and 2014 , respectively.

The Company has entered into several PPAs with Southern Power for capacity and energy. Expenses associated with these PPAs were $265 million , $179 million , and $144 million in 2016 , 2015 , and 2014 , respectively. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

The Company has a joint ownership agreement with Gulf Power under which Gulf Power owns a 25% portion of Plant Scherer Unit 3. Under this agreement, the Company operates Plant Scherer Unit 3 and Gulf Power reimburses the Company for its 25% proportionate share of the related non-fuel expenses, which were $8 million , $12 million , and $9 million in 2016 , 2015 , and 2014 , respectively. See Note 4 for additional information.

In 2014, prior to Southern Company's acquisition of PowerSecure on May 9, 2016, the Company entered into agreements with PowerSecure to build solar power generation facilities at two U.S. Army bases, as approved by the Georgia PSC. On October 4, 2016, the two facilities began commercial operation. Payments of approximately $118 million made by the Company to PowerSecure under the agreements since 2014 are included in utility plant in service at December 31, 2016 .

On September 1, 2016, Southern Company Gas acquired a 50% equity interest in Southern Natural Gas Company, L.L.C. (SNG). Prior to completion of the acquisition, SCS, as agent for the Company, had entered into a long-term interstate natural gas transportation agreement with SNG. The interstate transportation service provided to the Company by SNG pursuant to this agreement is governed by the terms and conditions of SNG's natural gas tariff and is subject to FERC regulation. For the period subsequent to Southern Company Gas' investment in SNG through December 31, 2016 , transportation costs under this agreement were approximately $35 million .

Prior to Southern Company's acquisition of Southern Company Gas, SCS, as agent for the Company, had agreements with certain subsidiaries of Southern Company Gas to purchase natural gas. For the period subsequent to Southern Company's acquisition of Southern Company Gas through December 31, 2016 , natural gas purchases made by the Company from Southern Company Gas' subsidiaries were approximately $10 million .

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2016 , 2015 , or 2014 .

The traditional electric operating companies, including the Company, and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

Regulatory Assets and Liabilities

The Company is subject to accounting requirements for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2016	2015	Note
	(in millions)		
Retiree benefit plans	**$ 1,348**	$ 1,307	(a, j)
Deferred income tax charges	**681**	683	(b, j)
Loss on reacquired debt	**137**	150	(c, j)
Asset retirement obligations	**893**	411	(b, j)
Vacation pay	**91**	91	(d, j)
Cancelled construction projects	**44**	56	(e)
Remaining net book value of retired assets	**166**	171	(f)
Storm damage reserves	**206**	92	(g)
Other regulatory assets	**97**	110	(h)
Other cost of removal obligations	**3**	(31)	(b)
Deferred income tax credits	**(121)**	(105)	(b, j)
Other regulatory liabilities	**(39)**	(2)	(i, j)
Total regulatory assets (liabilities), net	**$ 3,506**	$ 2,933	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Recovered and amortized over the average remaining service period which may range up to 13 years . See Note 2 for additional information.

(b) Asset retirement and other cost of removal obligations and deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 70 years . Asset retirement and removal liabilities will be settled and trued up following completion of the related activities. Included in the deferred income tax assets is $26 million for the retiree Medicare drug subsidy, which is recovered and amortized, as approved by the Georgia PSC, through 2022.

(c) Recovered over either the remaining life of the original issue or, if refinanced, over the remaining life of the new issue, which currently does not exceed 36 years .

(d) Recorded as earned by employees and recovered as paid, generally within one year . This includes both vacation and banked holiday pay.

(e) Costs associated with construction of environmental controls that will not be completed as a result of unit retirements are being amortized as approved by the Georgia PSC over periods not exceeding nine years or through 2022.

(f) Amortized as approved by the Georgia PSC over periods not exceeding 10 years or through 2024. The net book value of Plant Mitchell Unit 3 at December 31, 2016 was $12 million , which will continue to be amortized through December 31, 2019 as provided in the 2013 ARP. Amortization of the remaining net book value of Plant Mitchell Unit 3 at December 31, 2019, which is expected to be approximately $5 million , and $31 million related to obsolete inventories of certain retired units will be determined by the Georgia PSC in the 2019 base rate case. See Note 3 under "Retail Regulatory Matters – Integrated Resource Plan" for additional information.

(g) Previous under-recovery as of December 2013 is recorded and recovered or amortized as approved by the Georgia PSC through 2019. Amortization of $185 million related to the under-recovery from January 2014 through December 2016 will be determined by the Georgia PSC in the 2019 base rate case. See Note 3 for additional information.

(h) Comprised of several components including deferred nuclear outages, environmental remediation, building lease, and demand-side management tariff under-recovery. Deferred nuclear outages are recorded and recovered or amortized over the outage cycles of each nuclear unit, which does not exceed 24 months . The building lease is recorded and recovered or amortized as approved by the Georgia PSC through 2020. The amortization of environmental remediation and demand-side management tariff under-recovery of $46 million at December 31, 2016 will be determined by the Georgia PSC in the 2019 base rate case.

(i) Comprised primarily of fuel-hedging gains, which upon final settlement are refunded through the Company's fuel cost recovery mechanism.

(j) Generally not earning a return as they are excluded from rate base or are offset in rate base by a corresponding asset or liability.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

Revenues

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amount billable under the contract terms. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

Federal ITCs utilized are deferred and amortized to income as a credit to reduce depreciation over the average life of the related property. The Company had $83 million in federal ITCs at December 31, 2016 that will expire by 2036. State ITCs are recognized in the period in which the credits are generated. The Company had state investment and other tax credit carryforwards totaling $345 million at December 31, 2016, which will expire between 2019 and 2027 and are expected to be fully utilized by 2023.

The Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the cost of equity and debt funds used during construction.

The Company's property, plant, and equipment in service consisted of the following at December 31:

	2016	2015
	(in millions)	
Generation	**$ 16,668**	$ 15,386
Transmission	**5,779**	5,355
Distribution	**9,553**	9,151
General	**1,813**	1,921
Plant acquisition adjustment	**28**	28
Total plant in service	**$ 33,841**	$ 31,841

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling outage costs over the unit's operating cycle. The refueling cycles are 18 and 24 months for Plant Vogtle Units 1 and 2 and Plant Hatch Units 1 and 2, respectively.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.8% in 2016 , 2.7% in 2015 , and 2.7% in 2014 . Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

Under the terms of the 2013 ARP, the Company amortized approximately $14 million in each of 2014, 2015, and 2016 of its remaining regulatory liability related to other cost of removal obligations.

Asset Retirement Obligations and Other Costs of Removal

AROs are computed as the present value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. The Company has received accounting guidance from the Georgia PSC allowing the continued accrual and recovery of other retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for future obligations are reflected in the balance sheets as a regulatory liability and amounts to be recovered are reflected in the balance sheets as a regulatory asset.

The ARO liability primarily relates to the Company's ash ponds, landfills, and gypsum cells that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in April 2015 (CCR Rule). In addition, the Company has retirement obligations related to decommissioning of the Company's nuclear facilities, which include the Company's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, including the disposal of polychlorinated biphenyls in certain transformers; leasehold improvements; equipment on customer property; and property associated with the Company's rail lines and natural gas pipelines. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

Details of the AROs included in the balance sheets are as follows:

	2016	2015
	(in millions)	
Balance at beginning of year	**$ 1,916**	$ 1,255
Liabilities incurred	**—**	6
Liabilities settled	**(123)**	(30)
Accretion	**77**	56
Cash flow revisions	**662**	629
Balance at end of year	**$ 2,532**	$ 1,916

The increase in cash flow revisions in 2016 is primarily related to changes to the Company's closure strategy for ash ponds, landfills, and gypsum cells AROs.

The increase in cash flow revisions in 2015 is primarily related to changes to the Company's ash ponds, landfills, and gypsum cells ARO closure dollar and timing estimates associated with the CCR Rule and revisions to the nuclear decommissioning AROs based on the latest decommissioning study.

The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 2016 using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing with respect to compliance activities, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the Company expects to continue to periodically update these estimates.

Nuclear Decommissioning

The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Georgia PSC, as well as the IRS. While the

Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of the Company. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

The Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for AROs in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

The Funds participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to institutional investors for a fee. Securities loaned are fully collateralized by cash, letters of credit, and/or securities issued or guaranteed by the U.S. government or its agencies or instrumentalities. As of December 31, 2016 and 2015 , approximately $56 million and $76 million , respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $58 million and $78 million at December 31, 2016 and 2015 , respectively, and can only be sold by the borrower upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2016 , investment securities in the Funds totaled $814 million , consisting of equity securities of $326 million , debt securities of $477 million , and $11 million of other securities. At December 31, 2015 , investment securities in the Funds totaled $775 million , consisting of equity securities of $296 million , debt securities of $463 million , and $16 million of other securities. These amounts include the investment securities pledged to creditors and collateral received, and exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $803 million , $980 million , and $669 million in 2016 , 2015 , and 2014 , respectively, all of which were reinvested. For 2016 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $38 million , which included $14 million related to unrealized gains on securities held in the Funds at December 31, 2016 . For 2015 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $3 million , which included $26 million related to unrealized losses on securities held in the Funds at December 31, 2015 . For 2014 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $44 million , which included an immaterial amount related to unrealized gains and losses on securities held in the Funds at December 31, 2014 . While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of the securities and purpose for which the securities were acquired.

The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

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Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning are based on the most current study performed in 2015 . The site study costs and external trust funds for decommissioning as of December 31, 2016 based on the Company's ownership interests were as follows:

	Plant Hatch	Plant Vogtle Units 1 and 2
Decommissioning periods:		
Beginning year	2034	2047
Completion year	2075	2079
	(in millions)	
Site study costs:		
Radiated structures	$ 678	$ 568
Spent fuel management	160	147
Non-radiated structures	64	89
Total site study costs	$ 902	$ 804
External trust funds	$ 511	$ 303

For ratemaking purposes, the Company's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities and the site study estimate for spent fuel management as of 2012. Under the 2013 ARP, the Georgia PSC approved annual decommissioning cost for ratemaking of $4 million and $2 million for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 2.4% and an estimated trust earnings rate of 4.4% . The Company expects the Georgia PSC to review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs in the Company's 2019 base rate case.

Allowance for Funds Used During Construction

The Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. For the years 2016 , 2015 , and 2014 , the average AFUDC rates were 6.9% , 6.5% , and 5.6% , respectively, and AFUDC capitalized was $68 million , $56 million , and $62 million , respectively. AFUDC, net of income taxes, was 4.6% , 3.9% , and 4.6% of net income after dividends on preferred and preference stock for 2016 , 2015 , and 2014 , respectively. See Note 3 under "Retail Regulatory Matters – Nuclear Construction" for additional information on the inclusion of construction costs related to Plant Vogtle Units 3 and 4 in rate base effective January 1, 2011.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Storm Damage Recovery

The Company defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. Beginning January 1, 2014, the Company is accruing $30 million annually under the 2013 ARP that is recoverable through base rates. As of December 31, 2016 and December 31, 2015 , the balance in the regulatory asset related to storm damage was $206 million and $92 million , respectively, with approximately $30 million included in other regulatory assets, current for both years and approximately $176 million and $62 million included in other regulatory assets, deferred, respectively. The annual recovery amount is expected to be reviewed by the Georgia PSC and adjusted in future regulatory proceedings. As a result of this

regulatory treatment, costs related to storms are generally not expected to have a material impact on the Company's earnings. See Note 3 under "Retail Regulatory Matters – Storm Damage Recovery" for additional information.

Environmental Remediation Recovery

The Company maintains a reserve for environmental remediation as mandated by the Georgia PSC. In December 2013, the Georgia PSC approved the 2013 ARP including the recovery of approximately $2 million annually through the environmental compliance cost recovery (ECCR) tariff. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reduces the reserve as expenditures are incurred. Any difference between the liabilities accrued and cost recovered through rates is deferred as a regulatory asset or liability. The annual recovery amount is expected to be reviewed by the Georgia PSC and adjusted in future regulatory proceedings. As a result of this regulatory treatment, environmental remediation liabilities generally are not expected to have a material impact on the Company's earnings. As of December 31, 2016 , the balance of the environmental remediation liability was $17 million , with approximately $2 million included in other regulatory assets, current and approximately $33 million included as other regulatory assets, deferred. See Note 3 under "Environmental Matters – Environmental Remediation" for additional information.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, and oil, as well as transportation and emissions allowances. Fuel is recorded to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the Company through fuel cost recovery rates approved by the Georgia PSC. Emissions allowances granted by the EPA are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities on the balance sheets (included in "Other") and are measured at fair value. See Note 10 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the Georgia PSC-approved fuel-hedging program result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of income. Cash flows from derivatives are classified on the statements of cash flows in the same category as the hedged item. See Note 11 for additional information regarding derivatives.

Beginning in 2016, the Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under netting arrangements. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2016 .

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). On December 19, 2016, the Company voluntarily contributed $287 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2017 . The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the Georgia PSC and the FERC. For the year ending December 31, 2017 , no other postretirement trust contributions are expected.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the net periodic costs for the pension and other postretirement benefit plans for the following year and the benefit obligations as of the measurement date are presented below.

Assumptions used to determine net periodic costs:	**2016**	2015	2014
Pension plans			
Discount rate – benefit obligations	**4.65%**	4.18%	5.02%
Discount rate – interest costs	**3.86**	4.18	5.02
Discount rate – service costs	**5.03**	4.49	5.02
Expected long-term return on plan assets	**8.20**	8.20	8.20
Annual salary increase	**4.46**	3.59	3.59
Other postretirement benefit plans			
Discount rate – benefit obligations	**4.49%**	4.03%	4.85%
Discount rate – interest costs	**3.67**	4.03	4.85
Discount rate – service costs	**4.88**	4.39	4.85
Expected long-term return on plan assets	**6.27**	6.48	6.75
Annual salary increase	**4.46**	3.59	3.59

Assumptions used to determine benefit obligations:	**2016**	2015
Pension plans		
Discount rate	**4.40%**	4.65%
Annual salary increase	**4.46**	4.46
Other postretirement benefit plans		
Discount rate	**4.23%**	4.49%
Annual salary increase	**4.46**	4.46

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

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An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2016 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	6.50%	4.50%	2025
Post-65 medical	5.00	4.50	2025
Post-65 prescription	10.00	4.50	2025

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2016 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 55	$ 48
Service and interest costs	2	2

Pension Plans

The total accumulated benefit obligation for the pension plans was $3.5 billion at December 31, 2016 and $3.3 billion at December 31, 2015 . Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2016 and 2015 were as follows:

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 3,615**	$ 3,781
Service cost	**70**	73
Interest cost	**136**	154
Benefits paid	**(164)**	(188)
Actuarial (gain) loss	**143**	(205)
Balance at end of year	**3,800**	3,615
Change in plan assets		
Fair value of plan assets at beginning of year	**3,196**	3,383
Actual return (loss) on plan assets	**288**	(13)
Employer contributions	**301**	14
Benefits paid	**(164)**	(188)
Fair value of plan assets at end of year	**3,621**	3,196
Accrued liability	**$ (179)**	$ (419)

At December 31, 2016 , the projected benefit obligations for the qualified and non-qualified pension plans were $3.6 billion and $152 million , respectively. All pension plan assets are related to the qualified pension plan.

NOTES (continued)
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Amounts recognized in the balance sheets at December 31, 2016 and 2015 related to the Company's pension plans consist of the following:

	2016	2015
	(in millions)	
Other regulatory assets, deferred	**$ 1,129**	$ 1,076
Other current liabilities	**(14)**	(13)
Employee benefit obligations	**(165)**	(406)

Presented below are the amounts included in regulatory assets at December 31, 2016 and 2015 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2017 .

	2016	2015	Estimated Amortization in 2017
		(in millions)	
Prior service cost	**$ 17**	$ 8	**$ 3**
Net (gain) loss	**1,112**	1,068	**57**
Regulatory assets	**$ 1,129**	$ 1,076	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2016 and 2015 are presented in the following table:

	2016	2015
	(in millions)	
Regulatory assets:		
Beginning balance	**$ 1,076**	$ 1,102
Net (gain) loss	**99**	59
Change in prior service costs	**14**	—
Reclassification adjustments:		
Amortization of prior service costs	**(5)**	(9)
Amortization of net gain (loss)	**(55)**	(76)
Total reclassification adjustments	**(60)**	(85)
Total change	**53**	(26)
Ending balance	**$ 1,129**	$ 1,076

Components of net periodic pension cost were as follows:

	2016	2015	2014
		(in millions)	
Service cost	**$ 70**	$ 73	$ 62
Interest cost	**136**	154	153
Expected return on plan assets	**(258)**	(251)	(228)
Recognized net (gain) loss	**55**	76	41
Net amortization	**5**	9	10
Net periodic pension cost	**$ 8**	$ 61	$ 38

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the

market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2016 , estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2017	$ 184
2018	190
2019	196
2020	202
2021	206
2022 to 2026	1,126

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2016 and 2015 were as follows:

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 854**	$ 864
Service cost	**6**	7
Interest cost	**30**	34
Benefits paid	**(45)**	(45)
Actuarial (gain) loss	**(1)**	(22)
Plan amendment	**—**	12
Retiree drug subsidy	**3**	4
Balance at end of year	**847**	854
Change in plan assets		
Fair value of plan assets at beginning of year	**358**	395
Actual return (loss) on plan assets	**21**	(6)
Employer contributions	**17**	10
Benefits paid	**(42)**	(41)
Fair value of plan assets at end of year	**354**	358
Accrued liability	**$ (493)**	$ (496)

Amounts recognized in the balance sheets at December 31, 2016 and 2015 related to the Company's other postretirement benefit plans consist of the following:

	2016	2015
	(in millions)	
Other regulatory assets, deferred	**$ 213**	$ 223
Employee benefit obligations	**(493)**	(496)

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Presented below are the amounts included in regulatory assets at December 31, 2016 and 2015 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2017 .

	2016	2015	Estimated Amortization in 2017
		(in millions)	
Prior service cost	$ 6	$ 8	$ 1
Net (gain) loss	207	215	8
Regulatory assets	$ 213	$ 223	

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2016 and 2015 are presented in the following table:

	2016	2015
	(in millions)	
Regulatory assets:		
Beginning balance	$ 223	$ 213
Net (gain) loss	—	9
Change in prior service costs	—	12
Reclassification adjustments:		
Amortization of prior service costs	(1)	—
Amortization of net gain (loss)	(9)	(11)
Total reclassification adjustments	(10)	(11)
Total change	(10)	10
Ending balance	$ 213	$ 223

Components of the other postretirement benefit plans' net periodic cost were as follows:

	2016	2015	2014
		(in millions)	
Service cost	$ 6	$ 7	$ 6
Interest cost	30	34	34
Expected return on plan assets	(22)	(24)	(25)
Net amortization	10	11	2
Net periodic postretirement benefit cost	$ 24	$ 28	$ 17

NOTES (continued)
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Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in millions)	
2017	$ 54	$ (4)	$ 50
2018	56	(5)	51
2019	58	(5)	53
2020	59	(5)	54
2021	60	(6)	54
2022 to 2026	303	(32)	271

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2016 and 2015 , along with the targeted mix of assets for each plan, is presented below:

	Target	**2016**	2015
Pension plan assets:			
Domestic equity	26%	**29%**	30%
International equity	25	**22**	23
Fixed income	23	**29**	23
Special situations	3	**2**	2
Real estate investments	14	**13**	16
Private equity	9	**5**	6
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	36%	**35%**	34%
International equity	24	**24**	27
Domestic fixed income	33	**35**	25
Global fixed income			8
Special situations	1	**1**	—
Real estate investments	4	**4**	4
Private equity	2	**1**	2
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal

rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Trust-owned life insurance (TOLI).*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2016 and 2015 . The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- ***Domestic and international equity.*** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- ***Fixed income.*** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- ***TOLI.*** Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate account. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
- ***Real estate investments, private equity, and special situations investments.*** Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

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The fair values of pension plan assets as of December 31, 2016 and 2015 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. For 2015, investments in special situations were presented in the table below based on the nature of the investment.

	Fair Value Measurements Using				
As of December 31, 2016:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Assets:					
Domestic equity (*)	$ 686	$ 317	$ —	$ —	$ 1,003
International equity (*)	420	380	—	—	800
Fixed income:					
U.S. Treasury, government, and agency bonds	—	201	—	—	201
Mortgage- and asset-backed securities	—	4	—	—	4
Corporate bonds	—	338	—	—	338
Pooled funds	—	179	—	—	179
Cash equivalents and other	340	1	—	—	341
Real estate investments	106	—	—	394	500
Special situations	—	—	—	61	61
Private equity	—	—	—	188	188
Total	$ 1,552	$ 1,420	$ —	$ 643	$ 3,615

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

	Fair Value Measurements Using				
As of December 31, 2015:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Assets:					
Domestic equity (*)	$ 565	$ 236	$ —	$ —	$ 801
International equity (*)	412	343	—	—	755
Fixed income:					
U.S. Treasury, government, and agency bonds	—	157	—	—	157
Mortgage- and asset-backed securities	—	69	—	—	69
Corporate bonds	—	394	—	—	394
Pooled funds	—	173	—	—	173
Cash equivalents and other	—	50	—	—	50
Real estate investments	103	—	—	421	524
Private equity	—	—	—	220	220
Total	$ 1,080	$ 1,422	$ —	$ 641	$ 3,143

NOTES (continued)
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(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

The fair values of other postretirement benefit plan assets as of December 31, 2016 and 2015 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. For 2015, investments in special situations were presented in the table below based on the nature of the investment.

	Fair Value Measurements Using				
As of December 31, 2016:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Assets:					
Domestic equity (*)	$ 45	$ 9	$ —	$ —	$ 54
International equity (*)	11	37	—	—	48
Fixed income:					
U.S. Treasury, government, and agency bonds	—	5	—	—	5
Mortgage- and asset-backed securities	—	—	—	—	—
Corporate bonds	—	9	—	—	9
Pooled funds	—	38	—	—	38
Cash equivalents and other	15	—	—	—	15
Trust-owned life insurance	—	162	—	—	162
Real estate investments	3	—	—	11	14
Special situations	—	—	—	2	2
Private equity	—	—	—	5	5
Total	$ 74	$ 260	$ —	$ 18	$ 352

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

	Fair Value Measurements Using				
As of December 31, 2015:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Assets:					
Domestic equity (*)	$ 30	$ 36	$ —	$ —	$ 66
International equity (*)	12	41	—	—	53
Fixed income:					
U.S. Treasury, government, and agency bonds	—	5	—	—	5
Mortgage- and asset-backed securities	—	2	—	—	2
Corporate bonds	—	12	—	—	12
Pooled funds	—	30	—	—	30
Cash equivalents and other	10	6	—	—	16
Trust-owned life insurance	—	158	—	—	158
Real estate investments	3	—	—	12	15
Private equity	—	—	—	7	7
Total	$ 55	$ 290	$ —	$ 19	$ 364

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2016 , 2015 , and 2014 were $27 million , $26 million , and $25 million , respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

In 2011, plaintiffs filed a putative class action against the Company in the Superior Court of Fulton County, Georgia alleging that the Company's collection in rates of municipal franchise fees (all of which are remitted to municipalities) exceeded the amounts allowed in orders of the Georgia PSC and alleging certain state tort law claims. On November 16, 2016, the Georgia Court of Appeals reversed the trial court's previous dismissal of the case and remanded the case to the trial court for further proceedings. The Company has filed a petition for writ of certiorari with the Georgia Supreme Court. The Company believes the plaintiffs' claims have no merit and intends to vigorously defend itself in this matter. The ultimate outcome of this matter cannot be determined at this time.

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up affected sites. See Note 1 under "Environmental Remediation Recovery" for additional information.

The Company's environmental remediation liability as of December 31, 2016 was $17 million . The Company has been designated or identified as a potentially responsible party at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act, and assessment and potential cleanup of such sites is expected.

The ultimate outcome of these matters cannot be determined at this time; however, as a result of the Company's regulatory treatment for environmental remediation expenses described in Note 1 under "Environmental Remediation Recovery," these matters are not expected to have a material impact on the Company's financial statements.

Nuclear Fuel Disposal Costs

Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into contracts with the Company that require the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plant Hatch and Plant Vogtle Units 1 and 2 beginning no later than January 31, 1998. The DOE has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel. Consequently, the Company pursued and continues to pursue legal remedies against the U.S. government for its partial breach of contract.

In 2014, the Court of Federal Claims entered a judgment in favor of the Company in its spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. In March 2015, the Company recovered approximately $18 million , based on its ownership interests, which was credited to accounts where the original costs were charged and reduced rate base, fuel, and cost of service for the benefit of customers.

In 2014, the Company filed additional lawsuits against the U.S. government for the costs of continuing to store spent nuclear fuel at Plant Hatch and Plant Vogtle Units 1 and 2 for the period from January 1, 2011 through December 31, 2013. The damage period was subsequently extended to December 31, 2014. Damages will continue to accumulate until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2016 for any potential recoveries from the additional lawsuits. The final outcome of these matters cannot be determined at this time; however, no material impact on the Company's net income is expected.

On-site dry spent fuel storage facilities are operational at Plant Vogtle Units 1 and 2 and Plant Hatch. Facilities can be expanded to accommodate spent fuel through the expected life of each plant.

FERC Matters

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric operating companies' (including the Company's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies (including the Company) and Southern Power filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.

On December 9, 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. The traditional electric operating companies (including the Company) and Southern Power expect to make a

compliance filing within 30 days accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

The ultimate outcome of these matters cannot be determined at this time.

Retail Regulatory Matters

Rate Plans

Pursuant to the terms and conditions of a settlement agreement related to Southern Company's acquisition of Southern Company Gas approved by the Georgia PSC on April 14, 2016, the 2013 ARP will continue in effect until December 31, 2019, and the Company will be required to file its next base rate case by July 1, 2019. Furthermore, through December 31, 2019, the Company and Atlanta Gas Light Company each will retain their respective merger savings, net of transition costs, as defined in the settlement agreement; through December 31, 2022, such net merger savings applicable to each will be shared on a 60 / 40 basis with their respective customers; thereafter, all merger savings will be retained by customers.

In accordance with the 2013 ARP, the Georgia PSC approved increases to tariffs effective January 1, 2015 and 2016 as follows: (1) traditional base tariff rates by approximately $107 million and $49 million , respectively; (2) ECCR tariff by approximately $23 million and $75 million , respectively; (3) Demand-Side Management tariffs by approximately $3 million in each year; and (4) Municipal Franchise Fee tariff by approximately $3 million and $13 million , respectively, for a total increase in base revenues of approximately $136 million and $140 million , respectively.

Under the 2013 ARP, the Company's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00% . Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by the Company. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. In 2014, the Company's retail ROE exceeded 12.00% , and the Company refunded to retail customers approximately $11 million in 2016, as approved by the Georgia PSC on February 18, 2016. In 2015, the Company's retail ROE was within the allowed retail ROE range. In 2016, the Company's retail ROE exceeded 12.00% , and the Company expects to refund to retail customers approximately $40 million , subject to review and approval by the Georgia PSC. The ultimate outcome of this matter cannot be determined at this time.

Integrated Resource Plan

On July 28, 2016, the Georgia PSC approved the 2016 IRP including the decertification and retirement of Plant Mitchell Units 3, 4A, and 4B (217 MWs) and Plant Kraft Unit 1 (17 MWs) , as well as the decertification of the Intercession City unit (143 MWs total capacity) . On August 2, 2016, the Plant Mitchell and Plant Kraft units were retired. On August 31, 2016, the Company sold its 33% ownership interest in the Intercession City unit to Duke Energy Florida, LLC.

Additionally, the Georgia PSC approved the Company's environmental compliance strategy and related expenditures proposed in the 2016 IRP, including measures taken to comply with existing government-imposed environmental mandates, subject to limits on expenditures for Plant McIntosh Unit 1 and Plant Hammond Units 1 through 4.

The Georgia PSC approved the reclassification of the remaining net book value of Plant Mitchell Unit 3 and costs associated with materials and supplies remaining at the unit retirement date to a regulatory asset. Recovery of the unit's net book value will continue through December 31, 2019, as provided in the 2013 ARP. The timing of the recovery of the remaining balance of the unit's net book value as of December 31, 2019 and costs associated with materials and supplies remaining at the unit retirement date was deferred for consideration in the Company's 2019 base rate case.

The Georgia PSC also approved the Renewable Energy Development Initiative to procure an additional 1,200 MWs of renewable resources primarily utilizing market-based prices established through a competitive bidding process with expected in-service dates between 2018 and 2021. Additionally, 200 MWs of self-build capacity for use by the Company was approved, as well as consideration for no more than 200 MWs of capacity as part of a renewable commercial and industrial program.

The Georgia PSC also approved recovery of costs up to $99 million through June 30, 2019 to preserve nuclear as an option at a future generation site in Stewart County, Georgia. The timing of cost recovery will be determined by the Georgia PSC in a future base rate case. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In December 2015, the Georgia PSC approved the Company's request to lower annual billings by approximately $350 million effective January 1, 2016. On May 17, 2016, the Georgia PSC approved the Company's request to further lower annual billings by approximately $313 million effective

June 1, 2016. On December 6, 2016, the Georgia PSC approved the delay of the Company's next fuel case, which was previously scheduled to be filed by February 28, 2017. The Georgia PSC will review the Company's cumulative over or under recovered fuel balance no later than September 1, 2018 and evaluate the need to file a fuel case unless the Company deems it necessary to file a fuel case at an earlier time. Under an Interim Fuel Rider, the Company continues to be allowed to adjust its fuel cost recovery rates prior to the next fuel case if the under recovered fuel balance exceeds $200 million .

The Company's fuel cost recovery mechanism includes costs associated with a natural gas hedging program, as revised and approved by the Georgia PSC, allowing the use of an array of derivative instruments within a 48 -month time horizon effective January 1, 2016.

The Company's over recovered fuel balance totaled approximately $84 million at December 31, 2016 and is included in over recovered regulatory clause revenues, current. At December 31, 2015 , the Company's over recovered fuel balance totaled approximately $116 million , including $10 million in over recovered regulatory clause revenues, current and $106 million in other deferred credits and liabilities.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on the Company's revenues or net income, but will affect cash flow.

Storm Damage Recovery

As of December 31, 2016, the balance in the Company's regulatory asset related to storm damage was $206 million . During October 2016, Hurricane Matthew caused significant damage to the Company's transmission and distribution facilities. As of December 31, 2016, the Company had recorded incremental restoration cost related to this hurricane of $121 million , of which approximately $116 million was charged to the storm damage reserve and the remainder was capitalized. The Company is accruing $30 million annually through December 31, 2019, as provided in the 2013 ARP, to the storm damage reserve to cover the operations and maintenance costs of damages from major storms to its transmission and distribution facilities, which is recoverable through base rates. The rate of recovery of storm damage costs after December 31, 2019 is expected to be adjusted in the Company's 2019 base rate case. As a result of this regulatory treatment, costs related to storms are not expected to have a material impact on the Company's financial statements. See Note 1 under "Storm Damage Recovery" for additional information regarding the Company's storm damage reserve.

Nuclear Construction

In 2008, the Company, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, Vogtle Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc., which was subsequently acquired by Westinghouse and changed its name to WECTEC Global Project Services Inc. (WECTEC) (Westinghouse and WECTEC, collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement).

Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. The Vogtle 3 and 4 Agreement also provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees, subject to an aggregate cap of 10% of the contract price, or approximately $920 million to $930 million . In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which the Company has not been notified have occurred) with maximum additional capital costs under this provision attributable to the Company (based on the Company's ownership interest) of approximately $114 million . Each Vogtle Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7% . In the event of certain credit rating downgrades of any Vogtle Owner, such Vogtle Owner will be required to provide a letter of credit or other credit enhancement.

Certain obligations of Westinghouse have been guaranteed by Toshiba Corporation (Toshiba), Westinghouse's parent company. In the event of certain credit rating downgrades of Toshiba, Westinghouse is required to provide letters of credit or other credit enhancement. In December 2015, Toshiba experienced credit rating downgrades and Westinghouse provided the Vogtle Owners with $920 million of letters of credit. These letters of credit remain in place in accordance with the terms of the Vogtle 3 and 4 Agreement.

On February 14, 2017, Toshiba announced preliminary earnings results for the period ended December 31, 2016, which included a substantial goodwill impairment charge at Westinghouse attributed to increased cost estimates to complete its U.S. nuclear projects, including Plant Vogtle Units 3 and 4. Toshiba also warned that it will likely be in a negative equity position as a result of the charges. At the same time, Toshiba reaffirmed its commitment to its U.S. nuclear projects with implementation of management changes and increased oversight. An inability or failure by the Contractor to perform its obligations under the Vogtle 3 and 4 Agreement could have a material impact on the construction of Plant Vogtle Units 3 and 4.

Under the terms of the Vogtle 3 and 4 Agreement, the Contractor does not have a right to terminate the Vogtle 3 and 4 Agreement for convenience. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Vogtle Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events. In the event of an abandonment of work by the Contractor, the maximum liability of the Contractor under the Vogtle 3 and 4 Agreement is increased significantly, but remains subject to limitations. The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for convenience, provided that the Vogtle Owners will be required to pay certain termination costs.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4 with a certified capital cost of $4.418 billion . In addition, in 2009 the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows the Company to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved an NCCR tariff of $368 million for 2014, as well as increases to the NCCR tariff of approximately $27 million and $19 million effective January 1, 2015 and 2016, respectively.

The Company is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. In accordance with the 2009 certification order, the Company requested amendments to the Plant Vogtle Units 3 and 4 certificate in both the February 2013 (eighth VCM) and February 2015 (twelfth VCM) filings, when projected construction capital costs to be borne by the Company increased by 5% above the certified costs and estimated in-service dates were extended. In October 2013, the Georgia PSC approved a stipulation (2013 Stipulation) between the Company and the Georgia PSC Staff to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate until the completion of Plant Vogtle Unit 3 or earlier if deemed appropriate by the Georgia PSC and the Company. In April 2015, the Georgia PSC recognized that the certified cost and the 2013 Stipulation did not constitute a cost recovery cap and deemed the amendment requested in the February 2015 filing unnecessary and withdrawn until the completion of construction of Plant Vogtle Unit 3 consistent with the 2013 Stipulation.

On December 31, 2015, Westinghouse and the Vogtle Owners entered into a definitive settlement agreement (Contractor Settlement Agreement) to resolve disputes between the Vogtle Owners and the Contractor under the Vogtle 3 and 4 Agreement, including litigation that was pending in the U.S. District Court for the Southern District of Georgia (Vogtle Construction Litigation). Effective December 31, 2015, the Company, acting for itself and as agent for the other Vogtle Owners, and the Contractor entered into an amendment to the Vogtle 3 and 4 Agreement to implement the Contractor Settlement Agreement. The Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement (i) restrict the Contractor's ability to seek further increases in the contract price by clarifying and limiting the circumstances that constitute nuclear regulatory changes in law; (ii) provide for enhanced dispute resolution procedures; (iii) revise the guaranteed substantial completion dates to June 30, 2019 for Unit 3 and June 30, 2020 for Unit 4; (iv) provide that delay liquidated damages will commence if the nuclear fuel loading date for each unit does not occur by December 31, 2018 for Unit 3 and December 31, 2019 for Unit 4; and (v) provide that the Company, based on its ownership interest, will pay to the Contractor and capitalize to the project cost approximately $350 million , of which approximately $263 million had been paid as of December 31, 2016 . In addition, the Contractor Settlement Agreement provides for the resolution of other open existing items relating to the scope of the project under the Vogtle 3 and 4 Agreement, including cyber security, for which costs are reflected in the Company's current in-service forecast of $5.440 billion . Further, as part of the settlement and Westinghouse's acquisition of WECTEC: (i) Westinghouse engaged Fluor Enterprises, Inc., a subsidiary of Fluor Corporation, as a new construction subcontractor and (ii) the Vogtle Owners, Chicago Bridge & Iron Co, N.V., and The Shaw Group Inc. entered into mutual releases of any and all claims arising out of events or circumstances in connection with the construction of Plant Vogtle Units 3 and 4 that occurred on or before the date of the Contractor Settlement Agreement. On January 5, 2016, the Vogtle Construction Litigation was dismissed with prejudice.

On December 20, 2016, the Georgia PSC voted to approve a settlement agreement (Vogtle Cost Settlement Agreement) resolving the following prudence matters: (i) none of the $3.3 billion of costs incurred through December 31, 2015 and reflected in the fourteenth VCM report will be disallowed from rate base on the basis of imprudence; (ii) the Contractor Settlement Agreement is reasonable and prudent and none of the amounts paid or to be paid pursuant to the Contractor Settlement Agreement should be

disallowed from rate base on the basis of imprudence; (iii) financing costs on verified and approved capital costs will be deemed prudent provided they are incurred prior to December 31, 2019 and December 31, 2020 for Plant Vogtle Units 3 and 4, respectively; and (iv) (a) the in-service capital cost forecast will be adjusted to $5.680 billion (Revised Forecast), which includes a contingency of $240 million above the Company's current forecast of $5.440 billion , (b) capital costs incurred up to the Revised Forecast will be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, and (c) the Company would have the burden to show that any capital costs above the Revised Forecast are reasonable and prudent. Under the terms of the Vogtle Cost Settlement Agreement, the certified in-service capital cost for purposes of calculating the NCCR tariff will remain at $4.418 billion . Construction capital costs above $4.418 billion will accrue AFUDC through the date each unit is placed in service. The ROE used to calculate the NCCR tariff was reduced from 10.95% (the ROE rate setting point authorized by the Georgia PSC in the 2013 ARP) to 10.00% effective January 1, 2016. For purposes of the AFUDC calculation, the ROE on costs between $4.418 billion and $5.440 billion will also be 10.00% and the ROE on any amounts above $5.440 billion would be the Company's average cost of long-term debt. If the Georgia PSC adjusts the Company's ROE rate setting point in a rate case prior to Plant Vogtle Units 3 and 4 being placed into retail rate base, then the ROE for purposes of calculating both the NCCR tariff and AFUDC will likewise be 95 basis points lower than the revised ROE rate setting point. If Plant Vogtle Units 3 and 4 are not placed in service by December 31, 2020, then (i) the ROE for purposes of calculating the NCCR tariff will be reduced an additional 300 basis points, or $8 million per month, and may, at the Georgia PSC's discretion, be accrued to be used for the benefit of customers, until such time as the units are placed in service and (ii) the ROE used to calculate AFUDC will be the Company's average cost of long-term debt.

Under the terms of the Vogtle Cost Settlement Agreement, Plant Vogtle Units 3 and 4 will be placed into retail rate base on December 31, 2020 or when placed in service, whichever is later. The Georgia PSC will determine for retail ratemaking purposes the process of transitioning Plant Vogtle Units 3 and 4 from a construction project to an operating plant no later than the Company's base rate case required to be filed by July 1, 2019.

The Georgia PSC has approved fifteen VCM reports covering the periods through June 30, 2016, including construction capital costs incurred, which through that date totaled $3.7 billion . The Company expects to file the sixteenth VCM report, covering the period from July 1 through December 31, 2016, requesting approval of $222 million of construction capital costs incurred during that period, with the Georgia PSC by February 28, 2017. The Company's CWIP balance for Plant Vogtle Units 3 and 4 was approximately $3.9 billion as of December 31, 2016, and the Company had incurred $1.3 billion in financing costs through December 31, 2016.

As of December 31, 2016, the Company had borrowed $2.6 billion related to Plant Vogtle Units 3 and 4 costs through a loan guarantee agreement between the Company and the DOE and a multi-advance credit facility among the Company, the DOE, and the FFB. See Note 6 under "DOE Loan Guarantee Borrowings" for additional information, including applicable covenants, events of default, and mandatory prepayment events.

There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4 at the federal and state level and additional challenges may arise as construction proceeds. Processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance matters, including the timely resolution of Inspections, Tests, Analyses, and Acceptance Criteria and the related approvals by the NRC, may arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Vogtle Owners or the Contractor or to both.

In addition to Toshiba's reaffirmation of its commitment, the Contractor provided the Company with revised forecasted in-service dates of December 2019 and September 2020 for Plant Vogtle Units 3 and 4, respectively. The Company is currently reviewing a preliminary summary schedule supporting these dates that ultimately must be reconciled to a detailed integrated project schedule. As construction continues, the risk remains that challenges with Contractor performance including labor productivity, fabrication, delivery, assembly, and installation of plant systems, structures, and components, or other issues could arise and may further impact project schedule and cost. The Company expects the Contractor to employ mitigation efforts and believes the Contractor is responsible for any related costs under the Vogtle 3 and 4 Agreement. The Company estimates its financing costs for Plant Vogtle Units 3 and 4 to be approximately $30 million per month, with total construction period financing costs of approximately $2.5 billion . Additionally, the Company estimates its owner's costs to be approximately $6 million per month, net of delay liquidated damages.

The revised forecasted in-service dates are within the timeframe contemplated in the Vogtle Cost Settlement Agreement and would enable both units to qualify for production tax credits the IRS has allocated to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021. The net present value of the production tax credits is estimated at approximately $400 million per unit.

Future claims by the Contractor or the Company (on behalf of the Vogtle Owners) could arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement and, under the enhanced dispute resolution procedures, may be resolved through litigation after the completion of nuclear fuel load for both units.

The ultimate outcome of these matters cannot be determined at this time.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Alabama Power under a power contract. The Company and Alabama Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and a ROE. The Company's share of purchased power totaled $57 million in 2016 , $78 million in 2015 , and $84 million in 2014 and is included in purchased power, affiliates in the statements of income. The Company accounts for SEGCO using the equity method. See Note 7 under "Guarantees" for additional information.

The Company owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with one or more of the following entities: OPC, MEAG Power, Dalton, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has been contracted to operate and maintain the plants as agent for the co-owners and is jointly and severally liable for third party claims related to these plants. In addition, the Company jointly owns the Rocky Mountain pumped storage hydroelectric plant with OPC, which is the operator of the plant. On August 31, 2016, the Company sold its 33% ownership interest in the Intercession City combustion turbine unit to Duke Energy Florida, LLC.

At December 31, 2016 , the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation with the above entities were as follows:

Facility (Type)	Company Ownership	Plant in Service	Accumulated Depreciation	CWIP
			(in millions)	
Plant Vogtle (nuclear)				
Units 1 and 2	45.7%	$ 3,545	$ 2,111	$ 74
Plant Hatch (nuclear)	50.1	1,297	585	81
Plant Wansley (coal)	53.5	1,046	308	12
Plant Scherer (coal)				
Units 1 and 2	8.4	258	90	3
Unit 3	75.0	1,203	458	23
Rocky Mountain (pumped storage)	25.4	181	129	—

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income and the Company is responsible for providing its own financing.

The Company also owns 45.7% of Plant Vogtle Units 3 and 4, which are currently under construction and had a CWIP balance of approximately $3.9 billion as of December 31, 2016. See Note 3 under "Retail Regulatory Matters – Nuclear Construction" for additional information.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and various combined and separate state income tax returns. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2016	2015	2014
		(in millions)	
Federal –			
Current	$ 391	$ 515	$ 295
Deferred	319	176	366
	710	691	661
State –			
Current	6	81	82
Deferred	64	(3)	(14)
	70	78	68
Total	$ 780	$ 769	$ 729

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2016	2015
	(in millions)	
Deferred tax liabilities –		
Accelerated depreciation	$ 5,266	$ 4,909
Property basis differences	957	1,003
Employee benefit obligations	428	310
Premium on reacquired debt	56	61
Regulatory assets –		
Storm damage reserves	83	37
Employee benefit obligations	546	528
Asset retirement obligations	726	545
Retired assets	55	58
Asset retirement obligations	182	161
Other	83	92
Total	8,382	7,704
Deferred tax assets –		
Federal effect of state deferred taxes	173	150
Employee benefit obligations	661	642
Other property basis differences	105	88
Other deferred costs	100	83
State investment tax credit carryforward	201	216
Federal tax credit carryforward	84	3
Unbilled fuel revenue	47	47
Regulatory liabilities associated with asset retirement obligations	33	60
Asset retirement obligations	908	706
Other	70	82
Total	2,382	2,077
Accumulated deferred income taxes	$ 6,000	$ 5,627

The application of bonus depreciation provisions in current tax law significantly increased deferred tax liabilities related to accelerated depreciation in 2016 and 2015.

At December 31, 2016 , tax-related regulatory assets to be recovered from customers were $681 million . These assets are primarily attributable to tax benefits flowed through to customers in prior years and deferred taxes previously recognized at rates lower than the current enacted tax law.

At December 31, 2016 , tax-related regulatory liabilities to be credited to customers were $121 million . These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law.

In accordance with regulatory requirements, utilized federal ITCs are deferred and amortized over the average life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $10 million in each of 2016 , 2015 , and 2014 . State investment tax credits are recognized in the period in which the credits are generated and totaled $42 million in 2016 , $33 million in 2015 , and $34 million in 2014 . At December 31, 2016 , the Company had $83 million in federal ITC carryforwards that will expire by 2036 and $201 million in state ITC carryforwards that will expire between 2019 and 2027.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2016	2015	2014
Federal statutory rate	**35.0 %**	35.0 %	35.0 %
State income tax, net of federal deduction	**2.1**	2.5	2.2
Non-deductible book depreciation	**0.8**	1.2	1.3
AFUDC equity	**(0.8)**	(0.7)	(0.8)
Other	**(0.4)**	(0.4)	(0.7)
Effective income tax rate	**36.7 %**	37.6 %	37.0 %

On March 30, 2016, the FASB issued ASU 2016-09, which changes the accounting for income taxes for share-based payment award transactions. Entities are required to recognize all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation as income tax expense or benefit in the income statement. The adoption of ASU 2016-09 did not have a material impact on the Company's overall effective tax rate. See Note 1 under "Recently Issued Accounting Standards" for additional information.

Unrecognized Tax Benefits

The Company had no unrecognized tax benefits as of December 31, 2016 and no material changes in unrecognized tax benefits for any year presented.

The Company classifies interest on tax uncertainties as interest expense; however, the Company did not have any accrued interest or penalties for unrecognized tax benefits for any year presented.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months. The settlement of federal and state audits could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 through 2015 federal income tax returns and has received partial acceptance letters from the IRS; however, the IRS has not finalized its audits. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

6. FINANCING

Securities Due Within One Year

A summary of scheduled maturities of long-term debt due within one year at December 31 was as follows:

		2016		2015
		(in millions)		
Senior notes	**$**	**450**	$	700
Pollution control revenue bonds		**—**		4
Capital leases		**10**		8
Total	**$**	**460**	$	712

Maturities through 2021 applicable to total long-term debt are as follows: $460 million in 2017 ; $762 million in 2018 ; $513 million in 2019 ; $57 million in 2020 ; and $376 million in 2021 .

Senior Notes

In March 2016, the Company issued $325 million aggregate principal amount of Series 2016A 3.25% Senior Notes due April 1, 2026 and $325 million aggregate principal amount of Series 2016B 2.40% Senior Notes due April 1, 2021. An amount equal to the proceeds from the Series 2016A 3.25% Senior Notes due April 1, 2026 is being allocated to eligible green expenditures, including financing of or investments in solar generating facilities or electric vehicle charging infrastructure, or payments under PPAs served by solar or wind generating facilities. The proceeds from the Series 2016B 2.40% Senior Notes due April 1, 2021 were used to repay at maturity $250 million aggregate principal amount of the Company's Series 2013B Floating Rate Senior Notes due March 15, 2016, to repay a portion of the Company's short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

At December 31, 2016 and 2015 , the Company had $6.2 billion and $6.3 billion of senior notes outstanding, respectively, which included senior notes due within one year. These senior notes are effectively subordinated to all secured debt of the Company, which aggregated $2.8 billion and $2.4 billion at December 31, 2016 and 2015 , respectively. As of December 31, 2016 , the Company's secured debt included borrowings of $2.6 billion guaranteed by the DOE and capital lease obligations of $169 million . As of December 31, 2015 , the Company's secured debt included borrowings of $2.2 billion guaranteed by the DOE and capital lease obligations of $183 million . See Note 7 and "DOE Loan Guarantee Borrowings" herein for additional information.

Pollution Control Revenue Bonds

Pollution control revenue bond obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bond obligations outstanding at both December 31, 2016 and 2015 was $1.8 billion .

DOE Loan Guarantee Borrowings

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 (Title XVII Loan Guarantee Program), the Company and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement) in February 2014, under which the DOE agreed to guarantee the obligations of the Company under a note purchase agreement (FFB Note Purchase Agreement) among the DOE, the Company, and the FFB and a related promissory note (FFB Promissory Note). The FFB Note Purchase Agreement and the FFB Promissory Note provide for a multi-advance term loan facility (FFB Credit Facility), under which the Company may make term loan borrowings through the FFB.

Proceeds of advances made under the FFB Credit Facility are used to reimburse the Company for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Title XVII Loan Guarantee Program (Eligible Project Costs). Aggregate borrowings under the FFB Credit Facility may not exceed the lesser of (i) 70% of Eligible Project Costs or (ii) approximately $3.46 billion .

All borrowings under the FFB Credit Facility are full recourse to the Company, and the Company is obligated to reimburse the DOE for any payments the DOE is required to make to the FFB under the guarantee. The Company's reimbursement obligations to the DOE are full recourse and secured by a first priority lien on (i) the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor

core) and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. There are no restrictions on the Company's ability to grant liens on other property.

Advances may be requested under the FFB Credit Facility on a quarterly basis through 2020. The final maturity date for each advance under the FFB Credit Facility is February 20, 2044. Interest is payable quarterly and principal payments will begin on February 20, 2020. Borrowings under the FFB Credit Facility will bear interest at the applicable U.S. Treasury rate plus a spread equal to 0.375% .

In connection with its entry into the agreements with the DOE and the FFB, the Company incurred issuance costs of approximately $66 million , which are being amortized over the life of the borrowings under the FFB Credit Facility.

In June and December 2016, the Company made borrowings under the FFB Credit Facility in an aggregate principal amount of $300 million and $125 million , respectively. The interest rate applicable to the $300 million principal amount is 2.571% and the interest rate applicable to the $125 million principal amount is 3.142% , both for an interest period that extends to the final maturity date of February 20, 2044.

At December 31, 2016 and 2015 , the Company had $2.6 billion and $2.2 billion of borrowings outstanding under the FFB Credit Facility, respectively. Future advances are subject to satisfaction of customary conditions, as well as certification of compliance with the requirements of the Title XVII Loan Guarantee Program, including accuracy of project-related representations and warranties, delivery of updated project-related information, and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse Eligible Project Costs.

Under the Loan Guarantee Agreement, the Company is subject to customary borrower affirmative and negative covenants and events of default. In addition, the Company is subject to project-related reporting requirements and other project-specific covenants and events of default.

In the event certain mandatory prepayment events occur, the FFB's commitment to make further advances under the FFB Credit Facility will terminate and the Company will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facility over a period of five years (with level principal amortization). Among other things, these mandatory prepayment events include (i) the termination of the Vogtle 3 and 4 Agreement; (ii) cancellation of Plant Vogtle Units 3 and 4 by the Georgia PSC, or by the Company if authorized by the Georgia PSC; and (iii) cost disallowances by the Georgia PSC that could have a material adverse effect on completion of Plant Vogtle Units 3 and 4 or the Company's ability to repay the outstanding borrowings under the FFB Credit Facility. Under certain circumstances, insurance proceeds and any proceeds from an event of taking must be applied to immediately prepay outstanding borrowings under the FFB Credit Facility. The Company also may voluntarily prepay outstanding borrowings under the FFB Credit Facility. Under the FFB Promissory Note, any prepayment (whether mandatory or optional) will be made with a make-whole premium or discount, as applicable.

In connection with any cancellation of Plant Vogtle Units 3 and 4 that results in a mandatory prepayment event, the DOE may elect to continue construction of Plant Vogtle Units 3 and 4. In such an event, the DOE will have the right to assume the Company's rights and obligations under the principal agreements relating to Plant Vogtle Units 3 and 4 and to acquire all or a portion of the Company's ownership interest in Plant Vogtle Units 3 and 4.

Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as utility plant in service, and the related obligations are classified as long-term debt. At December 31, 2016 and 2015 , the Company had a capital lease asset for its corporate headquarters building of $61 million , with accumulated depreciation at December 31, 2016 and 2015 of $33 million and $26 million , respectively. At December 31, 2016 and 2015 , the capitalized lease obligation was $28 million and $35 million , respectively, with an annual interest rate of 7.9% for both years. For ratemaking purposes, the Georgia PSC has allowed the lease payments in cost of service with no return on the capital lease asset. The difference between the depreciation and the lease payments allowed for ratemaking purposes is recovered as operating expenses as ordered by the Georgia PSC. The annual operating expense incurred for this capital lease was not material for any year presented.

At December 31, 2016 and 2015 , the Company had capital lease assets related to two PPAs with Southern Power of $149 million , with accumulated amortization at December 31, 2016 and 2015 of $19 million and $10 million , respectively. At December 31, 2016 and 2015 , the related capitalized lease obligations were $141 million and $148 million , respectively. The annual interest rates range from 10% to 11% for these two capital lease PPAs. For ratemaking purposes, the Georgia PSC has included the capital lease asset amortization in cost of service and the interest in the Company's cost of debt. See Note 1 under "Affiliate Transactions" and Note 7 under "Fuel and Purchased Power Agreements" for additional information.

Assets Subject to Lien

See "DOE Loan Guarantee Borrowings" above for information regarding certain borrowings of the Company that are secured by a first priority lien on (i) the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4.

See "Capital Leases" above for information regarding certain assets held under capital leases.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company has shares of its Class A preferred stock, preference stock, and common stock outstanding. The Company's Class A preferred stock ranks senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. The outstanding series of the Class A preferred stock is subject to redemption at the option of the Company at any time at a redemption price equal to 100% of the par value. In addition, on or after October 1, 2017, the Company may redeem the outstanding series of the preference stock at a redemption price equal to 100% of the par value. With respect to any redemption of the preference stock prior to October 1, 2017, the redemption price includes a make-whole premium based on the present value of the liquidation amount and future dividends through the first par redemption date.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Bank Credit Arrangements

At December 31, 2016 , the Company had a $1.75 billion committed credit arrangement with banks, of which $1.73 billion was unused. This credit arrangement expires in 2020.

This bank credit arrangement requires payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than $^{1}/_{4}$ of 1% for the Company.

This bank credit arrangement contains a covenant that limits the Company's debt levels to 65% of total capitalization, as defined in the agreement. For purposes of this definition, debt excludes certain hybrid securities. At December 31, 2016 , the Company was in compliance with the debt limit covenant.

Subject to applicable market conditions, the Company expects to renew this bank credit arrangement, as needed, prior to expiration. In connection therewith, the Company may extend the maturity date and/or increase or decrease the lending commitments thereunder.

A portion of the $1.73 billion unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and its commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2016 was $868 million . In addition, at December 31, 2016, the Company had $250 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company makes short-term borrowings primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangement described above. Commercial paper is included in notes payable in the balance sheets.

Details of commercial paper borrowings outstanding were as follows:

	Commercial Paper at the End of the Period	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2016	**$ 392**	**1.1%**
December 31, 2015	$ 158	0.6%

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2016, 2015, and 2014, the Company incurred fuel expense of $1.8 billion , $2.0 billion , and $2.5 billion , respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

The Company has commitments regarding a portion of a 5% interest in the original cost of Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any capacity is available. The energy cost is a function of each unit's variable operating costs. Portions of the capacity payments relate to costs in excess of MEAG Power's Plant Vogtle Units 1 and 2 allowed investment for ratemaking purposes. The present value of these portions at the time of the disallowance was written off. Generally, the cost of such capacity and energy is included in purchased power, non-affiliates in the statements of income. Capacity payments totaled $11 million , $10 million , and $19 million in 2016, 2015, and 2014, respectively.

The Company has also entered into various long-term PPAs, some of which are accounted for as capital or operating leases. Total capacity expense under PPAs accounted for as operating leases was $217 million , $203 million , and $167 million for 2016, 2015, and 2014, respectively. Estimated total long-term obligations at December 31, 2016 were as follows:

	Affiliate Capital Leases	Affiliate Operating Leases	Non-Affiliate Operating Leases [c]	Vogtle Units 1 and 2 Capacity Payments	Total
			(in millions)		
2017	$ 22	$ 72	$ 123	$ 8	$ 225
2018	22	63	126	7	218
2019	23	64	127	6	220
2020	23	65	123	5	216
2021	24	66	124	5	219
2022 and thereafter	204	479	882	43	1,608
Total	$ 318	$ 809	$ 1,505	$ 74	$ 2,706
Less: amounts representing executory costs [(a)]	48				
Net minimum lease payments	270				
Less: amounts representing interest [(b)]	128				
Present value of net minimum lease payments	$ 142				

(a) Executory costs such as taxes, maintenance, and insurance (including the estimated profit thereon) a re estimated and included in total minimum lease payments.

(b) Calculated using an adjusted incremental borrowing rate to reduce the present value of the net minimum lease payments to fair value.

(c) A total of $197 million of biomass PPAs included under the non-affiliate operating leases is contingent upon the counterparties meeting specified contract dates for commercial operation. Subsequent to December 31, 2016, the specified contract dates for commercial operation were extended from 2017 to 2019 and may change further as a result of regulatory action.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional electric operating companies and Southern Power. Under these agreements, each of the traditional electric operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional electric operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

In addition to the PPA operating leases discussed above, the Company has other operating lease agreements with various terms and expiration dates. Total rent expense was $28 million for 2016 , $29 million for 2015 , and $28 million for 2014 . The Company includes any step rents, fixed escalations, and lease concessions in its computation of minimum lease payments.

As of December 31, 2016, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Other	Total
		(in millions)	
2017	$ 12	$ 7	$ 19
2018	6	7	13
2019	3	6	9
2020	3	6	9
2021	2	6	8
2022 and thereafter	2	13	15
Total	$ 28	$ 45	$ 73

Railcar minimum lease payments are disclosed at 100% of railcar lease obligations; however, a portion of these obligations is shared with the joint owners of Plants Scherer and Wansley. A majority of the rental expenses related to the railcar leases are recoverable through the fuel cost recovery clause as ordered by the Georgia PSC and the remaining portion is recovered through base rates.

In addition to the above rental commitments, the Company has obligations upon expiration of certain railcar leases with respect to the residual value of the leased property. These leases have terms expiring through 2024 with maximum obligations under these leases of $32 million . At the termination of the leases, the lessee may either renew the lease, exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

Alabama Power has guaranteed the obligations of SEGCO for $25 million of pollution control revenue bonds issued in 2001, which mature in June 2019, and also $100 million of senior notes issued in 2013, which mature in December 2018. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations corresponding to the Company's then proportionate ownership of SEGCO's stock if Alabama Power is called upon to make such payment under its guarantee. See Note 4 for additional information.

In addition, in 2013, the Company entered into an agreement that requires the Company to guarantee certain payments of a gas supplier for Plant McIntosh for a period up to 15 years . The guarantee is expected to be terminated if certain events occur within one year of the initial gas deliveries in 2018 . In the event the gas supplier defaults on payments, the maximum potential exposure under the guarantee is approximately $43 million .

As discussed earlier in this Note under "Operating Leases," the Company has entered into certain residual value guarantees related to railcar leases.

8. STOCK COMPENSATION

Stock-Based Compensation

Stock-based compensation primarily in the form of Southern Company performance share units may be granted through the Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2016 , there were 990 current and former employees participating in the stock option and performance share unit programs.

Stock Options

Through 2009, stock-based compensation granted to employees consisted exclusively of non-qualified stock options. The exercise price for stock options granted equaled the stock price of Southern Company common stock on the date of grant. Stock options vest on a pro rata basis over a maximum period of three years from the date of grant or immediately upon the retirement

or death of the employee. Options expire no later than 10 years after the grant date. All unvested stock options vest immediately upon a change in control where Southern Company is not the surviving corporation. Compensation expense is generally recognized on a straight-line basis over the three -year vesting period with the exception of employees that are retirement eligible at the grant date and employees that will become retirement eligible during the vesting period. Compensation expense in those instances is recognized at the grant date for employees that are retirement eligible and through the date of retirement eligibility for those employees that become retirement eligible during the vesting period. In 2015, Southern Company discontinued the granting of stock options.

The weighted average grant-date fair value of stock options granted during 2014 derived using the Black-Scholes stock option pricing model was $2.20 .

The compensation cost related to the grant of Southern Company stock options to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. Compensation cost and related tax benefits recognized in the Company's financial statements were not material for any year presented. As of December 31, 2016 , the amount of unrecognized compensation cost related to stock option awards not yet vested was immaterial.

The total intrinsic value of options exercised during the years ended December 31, 2016 , 2015 , and 2014 was $18 million , $9 million , and $19 million , respectively. No cash proceeds are received by the Company upon the exercise of stock options. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $7 million , $4 million , and $7 million for the years ended December 31, 2016 , 2015 , and 2014 , respectively. Prior to the adoption of ASU 2016-09, the excess tax benefits related to the exercise of stock options were recognized in the Company's financial statements with a credit to equity. Upon the adoption of ASU 2016-09, beginning in 2016, all tax benefits related to the exercise of stock options are recognized in income. As of December 31, 2016 , the aggregate intrinsic value for the options outstanding and options exercisable was $46 million and $41 million , respectively.

Performance Share Units

From 2010 through 2014, stock-based compensation granted to employees included performance share units in addition to stock options. Beginning in 2015, stock-based compensation consisted exclusively of performance share units. Performance share units granted to employees vest at the end of a three -year performance period. All unvested performance share units vest immediately upon a change in control where Southern Company is not the surviving corporation. Shares of Southern Company common stock are delivered to employees at the end of the performance period with the number of shares issued ranging from 0% to 200% of the target number of performance share units granted, based on achievement of the performance goals established by the Compensation Committee of the Southern Company Board of Directors.

The performance goal for all performance share units issued from 2010 through 2014 was based on the total shareholder return (TSR) for Southern Company common stock during the three -year performance period as compared to a group of industry peers. For these performance share units, at the end of three years , active employees receive shares based on Southern Company's performance while retired employees receive a pro rata number of shares based on the actual months of service during the performance period prior to retirement. The fair value of TSR-based performance share unit awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's common stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three -year performance period without remeasurement.

Beginning in 2015, Southern Company issued two additional types of performance share units to employees in addition to the TSR-based awards. These included performance share units with performance goals based on cumulative earnings per share (EPS) over the performance period and performance share units with performance goals based on Southern Company's equity-weighted ROE over the performance period. The EPS-based and ROE-based awards each represent 25% of total target grant date fair value of the performance share unit awards granted. The remaining 50% of the target grant date fair value consists of TSR-based awards. In contrast to the Monte Carlo simulation model used to determine the fair value of the TSR-based awards, the fair values of the EPS-based awards and the ROE-based awards are based on the closing stock price of Southern Company common stock on the date of the grant. Compensation expense for the EPS-based and ROE-based awards is generally recognized ratably over the three -year performance period initially assuming a 100% payout at the end of the performance period. The TSR-based performance share units, along with the EPS-based and ROE-based awards, vest immediately upon the retirement of the employee. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately while compensation expense for employees that become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility. The expected payout related to the EPS-based and ROE-based awards is reevaluated annually with expense recognized to date increased or decreased based on the number of shares currently

expected to be issued. Unlike the TSR-based awards, the compensation expense ultimately recognized for the EPS-based awards and the ROE-based awards will be based on the actual number of shares issued at the end of the performance period.

For the years ended December 31, 2016 , 2015 , and 2014 , employees of the Company were granted performance share units of 261,434 , 236,804 , and 176,224 , respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2016, 2015 , and 2014 , determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $45.17 , $46.41 , and $37.54 , respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2016 and 2015 was $48.84 and $47.78 , respectively.

For the years ended December 31, 2016 , 2015 , and 2014 , total compensation cost for performance share units recognized in income was $15 million , $15 million , and $6 million , respectively, with the related tax benefit also recognized in income of $6 million , $6 million , and $2 million , respectively. The compensation cost related to the grant of Southern Company performance share units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2016 , $4 million of total unrecognized compensation cost related to performance share award units will be recognized over a weighted-average period of approximately 22 months .

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Hatch and Plant Vogtle Units 1 and 2. The Act provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company, based on its ownership and buyback interests in all licensed reactors, is $247 million per incident, but not more than an aggregate of $37 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years . The next scheduled adjustment is due no later than September 10, 2018. See Note 4 for additional information on joint ownership agreements.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $1.5 billion for members' operating nuclear generating facilities. Additionally, the Company has NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $1.25 billion for nuclear losses in excess of the $1.5 billion primary coverage. In April 2014, NEIL introduced a new excess non-nuclear policy providing coverage up to $750 million for non-nuclear losses in excess of the $1.5 billion primary coverage.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks , with a maximum per occurrence per unit limit of $490 million . After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years . The Company purchases limits based on the projected full cost of replacement power, subject to ownership limitations, and has elected a 12-week deductible waiting period for each facility.

A builders' risk property insurance policy has been purchased from NEIL for the construction of Plant Vogtle Units 3 and 4. This policy provides the Vogtle Owners up to $2.75 billion for accidental property damage occurring during construction.

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The maximum annual assessments for the Company as of December 31, 2016 under the NEIL policies would be $82 million .

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12 -month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under

the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

10. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2016 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

	Fair Value Measurements Using			
As of December 31, 2016:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 44	$ —	$ 44
Interest rate derivatives	—	2	—	2
Nuclear decommissioning trusts: (*)				
Domestic equity	204	1	—	205
Foreign equity	—	121	—	121
U.S. Treasury and government agency securities	—	71	—	71
Municipal bonds	—	73	—	73
Corporate bonds	—	164	—	164
Mortgage and asset backed securities	—	164	—	164
Other	11	5	—	16
Total	$ 215	$ 645	$ —	$ 860
Liabilities:				
Energy-related derivatives	$ —	$ 8	$ —	$ 8
Interest rate derivatives	—	3	—	3
Total	$ —	$ 11	$ —	$ 11

(*) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

NOTES (continued)
Georgia Power Company 2016 Annual Report

As of December 31, 2015 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

	Fair Value Measurements Using			
As of December 31, 2015:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 2	$ —	$ 2
Interest rate derivatives	—	5	—	5
Nuclear decommissioning trusts: (*)				
Domestic equity	182	1	—	183
Foreign equity	—	113	—	113
U.S. Treasury and government agency securities	—	125	—	125
Municipal bonds	—	64	—	64
Corporate bonds	—	143	—	143
Mortgage and asset backed securities	—	127	—	127
Other	16	4	—	20
Cash equivalents	63	—	—	63
Total	$ 261	$ 584	$ —	$ 845
Liabilities:				
Energy-related derivatives	$ —	$ 15	$ —	$ 15
Interest rate derivatives	—	6	—	6
Total	$ —	$ 21	$ —	$ 21

(*) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflects the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and occasionally, implied volatility of interest rate options. The interest rate derivatives are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 11 for additional information on how these derivatives are used.

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. For fair value measurements of the investments within the nuclear decommissioning trusts, external pricing vendors are designated for each asset class with each security specifically assigned a primary pricing source. For investments held within commingled funds, fair value is determined at the end of each business day through the net asset value, which is established by obtaining the underlying securities' individual prices from the primary pricing source. A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, fixed income market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing

systems, and mathematical tools. Dealer quotes and other market information, including live trading levels and pricing analysts' judgments, are also obtained when available. See Note 1 under "Nuclear Decommissioning" for additional information.

As of December 31, 2016 and 2015 , other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt, including securities due within one year:		
2016	**$ 10,516**	**$ 11,034**
2015	$ 10,145	$ 10,480

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on current rates available to the Company.

11. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net basis. See Note 10 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in energy-related commodity prices. The Company manages a fuel-hedging program through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. At December 31, 2016 and 2015, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Through December 31, 2015, the Company's fuel-hedging program had a time horizon up to 24 months . Effective January 1, 2016, the Georgia PSC approved changes to the Company's hedging program allowing it to use an array of derivative instruments within a 48 -month time horizon.

Energy-related derivative contracts are accounted for under one of two methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging program, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery mechanism.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2016 , the net volume of energy-related derivative contracts for natural gas positions totaled 155 million mmBtu, all of which expire by 2020 , which is the longest hedge date.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The expected volume of natural gas subject to such a feature is 3 million mmBtu for the Company.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings, with any ineffectiveness recorded directly to earnings. At December 31, 2016, there were no cash flow hedges outstanding. Derivatives related to fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains and losses and the hedged items' fair value gains and losses attributable to interest rate risk are both recorded directly to earnings, providing an offset, with any differences representing ineffectiveness.

At December 31, 2016 , the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2016
	(in millions)				*(in millions)*
Fair Value Hedges of Existing Debt					
	$ 250	5.40%	3-month LIBOR + 4.02%	June 2018	$ —
	500	1.95%	3-month LIBOR + 0.76%	December 2018	(2)
	200	4.25%	3-month LIBOR + 2.46%	December 2019	1
Total	$ 950				$ (1)

The estimated pre-tax gains (losses) that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2017 total $4 million . Deferred gains and losses related to interest rate derivative settlements of cash flow hedges are expected to be amortized into earnings through 2037 .

Derivative Financial Statement Presentation and Amounts

The Company enters into energy-related and interest rate derivative contracts that may contain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. At December 31, 2016, fair value amounts of derivative assets and liabilities on the balance sheets are presented net to the extent that there are netting arrangements or similar agreements with the counterparties. At December 31, 2015, the fair value amounts of derivative instruments were presented gross on the balance sheets.

NOTES (continued)
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At December 31, 2016 and 2015, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	2016		2015	
Derivative Category and Balance Sheet Location	**Assets**	**Liabilities**	Assets	Liabilities
		(in millions)		
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Other current liabilities	**$ 30**	**$ 1**	$ 2	$ 12
Other deferred charges and assets/Other deferred credits and liabilities	**14**	**7**	—	3
Total derivatives designated as hedging instruments for regulatory purposes	**$ 44**	**$ 8**	$ 2	$ 15
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Interest rate derivatives:				
Other current assets/Other current liabilities	**$ 2**	**$ —**	$ 5	$ —
Other deferred charges and assets/Other deferred credits and liabilities	**—**	**3**	—	6
Total derivatives designated as hedging instruments in cash flow and fair value hedges	**$ 2**	**$ 3**	$ 5	$ 6
Gross amounts recognized	**$ 46**	**$ 11**	$ 7	$ 21
Gross amounts offset	**$ (8)**	**$ (8)**	$ (6)	$ (6)
Net amounts recognized in the Balance Sheets (*)	**$ 38**	**$ 3**	$ 1	$ 15

(*) At December 31, 2015 , the fair value amounts for derivative contracts subject to netting arrangements were presented gross on the balance sheet.

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2016 and 2015 .

At December 31, 2016 and 2015 , the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivatives designated as regulatory hedging instruments and deferred were as follows:

	Unrealized Losses			**Unrealized Gains**		
Derivative Category	**Balance Sheet Location**	**2016**	2015	**Balance Sheet Location**	**2016**	2015
		(in millions)			*(in millions)*	
Energy-related derivatives: (*)	Other regulatory assets, current	**$ —**	$ (12)	Other regulatory liabilities, current	**$ 29**	$ 2
	Other regulatory assets, deferred	**—**	(3)	Other deferred credits and liabilities	**7**	—
Total energy-related derivative gains (losses)		**$ —**	$ (15)		**$ 36**	$ 2

(*) At December 31, 2016 , the unrealized gains and losses for energy-related derivative contracts subject to netting arrangements were presented net on the balance sheet. At December 31, 2015 , the unrealized gains and losses for energy-related derivative contracts subject to netting arrangements were presented gross on the balance sheet.

For the years ended December 31, 2016 , 2015 , and 2014 , the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	**2016**	2015	2014	**Statements of Income Location**	**2016**	2015	2014
		(in millions)				*(in millions)*	
Interest rate derivatives	**$ —**	$ (15)	$ (8)	Interest expense, net of amounts capitalized	**$ (4)**	$ (3)	$ (3)

For the years ended December 31, 2016 and 2015 , the pre-tax effects of interest rate derivatives designated as fair value hedging instruments on the statements of income were immaterial on a gross basis for the Company. Furthermore, the pre-tax effect of interest rate derivatives designated as fair value hedging instruments on the Company's statements of income were offset by changes to the carrying value of long-term debt. The gains and losses related to interest rate derivative settlements of fair value hedges are recorded directly to earnings.

There was no material ineffectiveness recorded in earnings for any period presented. The pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was immaterial for all years presented.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2016 , the Company's collateral posted with its derivative counterparties was immaterial.

At December 31, 2016 , the fair value of derivative liabilities with contingent features, including certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade because of joint and several liability features underlying these derivatives, was immaterial.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2016 and 2015 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2016	**$ 1,872**	**$ 509**	**$ 269**
June 2016	**2,051**	**656**	**349**
September 2016	**2,698**	**1,054**	**599**
December 2016	**1,762**	**258**	**113**
March 2015	$ 1,978	$ 454	$ 236
June 2015	2,016	554	277
September 2015	2,691	964	551
December 2015	1,641	376	196

In accordance with the adoption of ASU 2016-09 (see Note 1 under "Recently Issued Accounting Standards"), previously reported amounts for income tax expense were reduced by $1 million in the third quarter 2016, $2 million in the second quarter 2016, and $1 million in the first quarter 2016.

The Company's business is influenced by seasonal weather conditions.

SELECTED FINANCIAL AND OPERATING DATA 2012 - 2016
Georgia Power Company 2016 Annual Report

	2016	2015	2014	2013	2012
Operating Revenues (in millions)	$ 8,383	$ 8,326	$ 8,988	$ 8,274	$ 7,998
Net Income After Dividends on Preferred and Preference Stock (in millions)	$ 1,330	$ 1,260	$ 1,225	$ 1,174	$ 1,168
Cash Dividends on Common Stock (in millions)	$ 1,305	$ 1,034	$ 954	$ 907	$ 983
Return on Average Common Equity (percent)	12.05	11.92	12.24	12.45	12.76
Total Assets (in millions) [a][b]	$ 34,835	$ 32,865	$ 30,872	$ 28,776	$ 28,618
Gross Property Additions (in millions)	$ 2,314	$ 2,332	$ 2,146	$ 1,906	$ 1,838
Capitalization (in millions):					
Common stock equity	$ 11,356	$ 10,719	$ 10,421	$ 9,591	$ 9,273
Preferred and preference stock	266	266	266	266	266
Long-term debt [a]	10,225	9,616	8,563	8,571	7,928
Total (excluding amounts due within one year)	$ 21,847	$ 20,601	$ 19,250	$ 18,428	$ 17,467
Capitalization Ratios (percent):					
Common stock equity	52.0	52.0	54.1	52.0	53.1
Preferred and preference stock	1.2	1.3	1.4	1.4	1.5
Long-term debt [a]	46.8	46.7	44.5	46.6	45.4
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	2,155,945	2,127,658	2,102,673	2,080,358	2,062,040
Commercial [c]	305,488	302,891	300,186	297,493	295,523
Industrial [c]	10,537	10,429	10,192	10,063	10,017
Other	9,585	9,261	9,003	8,623	7,724
Total	2,481,555	2,450,239	2,422,054	2,396,537	2,375,304
Employees (year-end)	7,527	7,989	7,909	7,886	8,094

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $124 million, $62 million, and $67 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(b) A reclassification of deferred tax assets from Total Assets of $34 million, $68 million, and $117 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(c) A reclassification of customers from commercial to industrial is reflected for years 2012-2015 to be consistent with the rate structure approved by the Georgia PSC. The impact to operating revenues, kilowatt-hour sales, and average revenue per kilowatt-hour by class is not material.

SELECTED FINANCIAL AND OPERATING DATA 2012 - 2016 (continued)
Georgia Power Company 2016 Annual Report

	2016	2015	2014	2013	2012
Operating Revenues (in millions):					
Residential	$ 3,318	$ 3,240	$ 3,350	$ 3,058	$ 2,986
Commercial	3,077	3,094	3,271	3,077	2,965
Industrial	1,291	1,305	1,525	1,391	1,322
Other	86	88	94	94	89
Total retail	7,772	7,727	8,240	7,620	7,362
Wholesale — non-affiliates	175	215	335	281	281
Wholesale — affiliates	42	20	42	20	20
Total revenues from sales of electricity	7,989	7,962	8,617	7,921	7,663
Other revenues	394	364	371	353	335
Total	$ 8,383	$ 8,326	$ 8,988	$ 8,274	$ 7,998
Kilowatt-Hour Sales (in millions):					
Residential	27,585	26,649	27,132	25,479	25,742
Commercial	32,932	32,719	32,426	31,984	32,270
Industrial	23,746	23,805	23,549	23,087	23,089
Other	610	632	633	630	641
Total retail	84,873	83,805	83,740	81,180	81,742
Wholesale — non-affiliates	3,415	3,501	4,323	3,029	2,934
Wholesale — affiliates	1,398	552	1,117	496	600
Total	89,686	87,858	89,180	84,705	85,276
Average Revenue Per Kilowatt-Hour (cents):					
Residential	12.03	12.16	12.35	12.00	11.60
Commercial	9.34	9.46	10.09	9.62	9.19
Industrial	5.44	5.48	6.48	6.03	5.73
Total retail	9.16	9.22	9.84	9.39	9.01
Wholesale	4.51	5.80	6.93	8.54	8.52
Total sales	8.91	9.06	9.66	9.35	8.99
Residential Average Annual Kilowatt-Hour Use Per Customer	12,864	12,582	12,969	12,293	12,509
Residential Average Annual Revenue Per Customer	$ 1,557	$ 1,529	$ 1,605	$ 1,475	$ 1,451
Plant Nameplate Capacity Ratings (year-end) (megawatts)	15,274	15,455	17,593	17,586	17,984
Maximum Peak-Hour Demand (megawatts):					
Winter	14,527	15,735	16,308	12,767	14,104
Summer	16,244	16,104	15,777	15,228	16,440
Annual Load Factor (percent)	61.9	61.9	61.2	63.5	59.1
Plant Availability (percent):					
Fossil-steam	87.4	85.6	86.3	87.1	90.3
Nuclear	95.6	94.1	90.8	91.8	94.1
Source of Energy Supply (percent):					
Coal	26.4	24.5	30.9	26.4	26.6
Nuclear	17.6	17.6	16.7	17.7	18.3
Hydro	1.1	1.6	1.3	2.0	0.7
Oil and gas	28.2	28.3	26.3	29.6	22.0
Purchased power —					
From non-affiliates	6.7	5.0	3.8	3.3	6.8
From affiliates	20.0	23.0	21.0	21.0	25.6
Total	100.0	100.0	100.0	100.0	100.0

GULF POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Gulf Power Company 2016 Annual Report

The management of Gulf Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2016 .

/s/ S. W. Connally, Jr.
S. W. Connally, Jr.
Chairman, President, and Chief Executive Officer

/s/ Xia Liu
Xia Liu
Vice President and Chief Financial Officer

February 21, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Gulf Power Company

We have audited the accompanying balance sheets and statements of capitalization of Gulf Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2016 and 2015 , and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2016 . These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-342 to II-379) present fairly, in all material respects, the financial position of Gulf Power Company as of December 31, 2016 and 2015 , and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016 , in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 21, 2017

DEFINITIONS

Term	Meaning
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ARO	Asset retirement obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
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
IRS	Internal Revenue Service
ITC	Investment tax credit
KWH	Kilowatt-hour
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
OCI	Other comprehensive income
power pool	The operating arrangement whereby the integrated generating resources of the traditional 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
ROE	Return on equity
S&P	S&P Global Ratings, a division of S&P Global Inc.
scrubber	Flue gas desulfurization system
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
Southern Company	The Southern Company
Southern Company Gas	Southern Company Gas (formerly known as AGL Resources Inc.) and its subsidiaries
Southern Company system	Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), Southern Electric Generating Company, Southern Nuclear, SCS, Southern LINC, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries
Southern LINC	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional electric operating companies	Alabama Power, Georgia Power, Gulf Power Company, and Mississippi Power

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Gulf Power Company 2016 Annual Report

OVERVIEW

Business Activities

Gulf Power Company (the Company) operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located in northwest Florida and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of providing electric service. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, stringent environmental standards, reliability, restoration following major storms, fuel, and capital expenditures. Effectively operating pursuant to these regulatory mechanisms and appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future. Through 2015, long-term non-affiliate capacity sales from the Company's ownership of Plant Scherer Unit 3 (205 MWs) provided the majority of the Company's wholesale earnings. Contract expirations at the end of 2015 and the end of May 2016 related to Plant Scherer Unit 3 wholesale sales had a material negative impact on the Company's earnings in 2016. Remaining contract sales from Plant Scherer Unit 3 cover approximately 24% of the Company's ownership of the unit through 2019.

In 2013, the Florida PSC approved the settlement agreement (2013 Rate Case Settlement Agreement) among the Company and all of the intervenors to the Company's retail base rate case. Under the terms of the 2013 Rate Case Settlement Agreement, the Company (1) increased base rates approximately $35 million and $20 million annually effective January 2014 and 2015, respectively; (2) continued its authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); (3) may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017, of which $28.5 million had been recorded as of December 31, 2016; and (4) accrued a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 through January 1, 2017.

On October 12, 2016, the Company filed a petition (2016 Rate Case) with the Florida PSC requesting an annual increase in retail rates and charges of $106.8 million based on the projected test year of January 1, 2017 through December 31, 2017 and a retail ROE of 11% compared to the current retail ROE of 10.25%. The requested increase includes recovery of the portion of Plant Scherer Unit 3 that has been rededicated to serving retail customers following the contract expirations discussed above. If retail recovery of Plant Scherer Unit 3 is not approved by the Florida PSC in the 2016 Rate Case, the Company may consider an asset sale. The current book value of the Company's ownership of Plant Scherer Unit 3 could exceed market value which could result in a material loss. The Florida PSC is expected to make a decision on the 2016 Rate Case in the second quarter 2017. The Company has requested that the increase in base rates, if approved by the Florida PSC, become effective in July 2017.

On November 2, 2016, the Florida PSC approved the Company's 2017 annual cost recovery clause factors. The fuel and environmental factors include certain costs associated with the ongoing ownership and operation of Plant Scherer Unit 3. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Cost Recovery Clauses" herein for additional information.

The Company continues to focus on several key performance indicators including, but not limited to, customer satisfaction, plant availability, system reliability, and net income after dividends on preference stock. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys to evaluate the Company's results and generally targets the top quartile of these surveys in measuring performance.

See RESULTS OF OPERATIONS herein for information on the Company's financial performance.

Earnings

The Company's 2016 net income after dividends on preference stock was $131 million , representing a $17 million, or 11.5%, decrease over the previous year. The decrease was primarily due to lower wholesale revenues and higher depreciation, partially offset by higher retail revenues and lower operations and maintenance expenses as compared to the corresponding period in 2015.

In 2015 , the net income after dividends on preference stock was $148 million, representing an $8 million, or 5.7%, increase over the previous year. The increase was primarily due to an increase in retail base revenues effective January 1, 2015 and a reduction in depreciation, both as authorized in the 2013 Rate Case Settlement Agreement, partially offset by higher operations and maintenance expenses as compared to the corresponding period in 2014.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2016 Annual Report

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2016	**2016**	2015
		(in millions)	
Operating revenues	**$ 1,485**	**$ 2**	$ (107)
Fuel	**432**	**(13)**	(160)
Purchased power	**142**	**7**	28
Other operations and maintenance	**336**	**(18)**	13
Depreciation and amortization	**172**	**31**	(4)
Taxes other than income taxes	**120**	**2**	7
Total operating expenses	**1,202**	**9**	(116)
Operating income	**283**	**(7)**	9
Total other income and (expense)	**(52)**	**(11)**	3
Income taxes	**91**	**(1)**	4
Net income	**140**	**(17)**	8
Dividends on preference stock	**9**	**—**	—
Net income after dividends on preference stock	**$ 131**	**$ (17)**	$ 8

Operating Revenues

Operating revenues for 2016 were $1.49 billion , reflecting an increase of $2 million from 2015 . Details of operating revenues were as follows:

	Amount	
	2016	2015
	(in millions)	
Retail — prior year	**$ 1,249**	$ 1,267
Estimated change resulting from –		
Rates and pricing	**30**	22
Sales growth	**—**	—
Weather	**1**	3
Fuel and other cost recovery	**1**	(43)
Retail — current year	**1,281**	1,249
Wholesale revenues –		
Non-affiliates	**61**	107
Affiliates	**75**	58
Total wholesale revenues	**136**	165
Other operating revenues	**68**	69
Total operating revenues	**$ 1,485**	$ 1,483
Percent change	**N/M**	(6.7)%

N/M - Not meaningful

In 2016 , retail revenues increased $32 million, or 2.6%, when compared to 2015 primarily as a result of an increase in the Company's environmental cost recovery clause revenues, partially offset by a decrease in the energy conservation clause revenues. In 2015 , retail revenues decreased $18 million, or 1.4%, when compared to 2014 primarily as a result of lower fuel cost recovery revenues partially offset by higher revenues associated with purchased power capacity costs and higher revenues resulting from an increase in retail base rates, as authorized in the 2013 Rate Case Settlement Agreement, as well as an increase in

the environmental and energy conservation cost recovery clause rates, both effective in January 2015. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth and weather.

In 2016 , revenues associated with changes in rates and pricing increased primarily due to an increase in the environmental cost recovery clause as a result of additional rate base investment related to environmental compliance equipment placed in service at the end of 2015 as well as portions of the Company's ownership in Plant Scherer Unit 3 that were rededicated to retail service in 2016. In 2015 , revenues associated with changes in rates and pricing included higher revenues due to increases in retail base rates and the Company's environmental and energy conservation cost recovery clauses. Annually, the Company petitions the Florida PSC for recovery of projected environmental and energy conservation costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions include related expenses and a return on average net investment.

Fuel and other cost recovery provisions include fuel expenses, the energy component of purchased power costs, purchased power capacity costs, and the difference between projected and actual costs and revenues related to energy conservation and environmental compliance. Annually, the Company petitions the Florida PSC for recovery of projected fuel and purchased power costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions generally equal the related expenses and have no material effect on earnings.

See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information regarding the Company's retail base rate case and cost recovery clauses, including the Company's fuel cost recovery, purchased power capacity recovery, environmental cost recovery, and energy conservation cost recovery clauses.

Wholesale revenues from power sales to non-affiliated utilities were as follows:

	2016	2015	2014
		(in millions)	
Capacity and other	**$ 30**	$ 67	$ 65
Energy	**31**	40	64
Total non-affiliated	**$ 61**	$ 107	$ 129

Wholesale revenues from sales to non-affiliates consist of long-term sales agreements to other utilities in Florida and Georgia and short-term opportunity sales. Capacity revenues from long-term sales agreements represent the greatest contribution to net income. The energy is generally sold at variable cost. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost of energy. Wholesale energy revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation. See FUTURE EARNINGS POTENTIAL – "General" for additional information regarding the expiration of long-term sales agreements for Plant Scherer Unit 3, which will materially impact future wholesale earnings.

In 2016 , wholesale revenues from sales to non-affiliates decreased $46 million, or 43.0%, as compared to the prior year primarily due to a 55.3% decrease in capacity revenues resulting from the expiration of Plant Scherer Unit 3 long-term sales agreements at the end of 2015 and the end of May 2016. In 2015 , wholesale revenues from sales to non-affiliates decreased $22 million, or 17.1%, as compared to the prior year primarily due to a 37.7% decrease in KWH sales resulting from lower sales under the Plant Scherer Unit 3 long-term sales agreements due to a planned outage and lower natural gas prices that led to increased self-generation from customer-owned units.

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These transactions do not have a significant impact on earnings since the revenue related to these energy sales generally offsets the cost of energy sold. In 2016 , wholesale revenues from sales to affiliates increased $17 million, or 29.3%, as compared to the prior year primarily due to a 46.1% increase in KWH sales to affiliates due to lower planned unit outages for the Company's generation resources and a 7.9% increase in the price of energy sold to affiliates due to more sales during peak load hours. In 2015 , wholesale revenues from sales to affiliates decreased $72 million, or 55.4%, as compared to the prior year primarily due to a 23.5% decrease in the price of energy sold to affiliates due to lower power pool interchange rates resulting from lower natural gas prices and a 42.0% decrease in KWH sales that resulted from the availability of lower-cost generation alternatives.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2016 Annual Report

In 2016, other operating revenues decreased by an immaterial amount compared to 2015. In 2015, other operating revenues increased $5 million, or 7.8%, as compared to the prior year primarily due to a $2 million increase in franchise fees and a $2 million increase in revenues from other energy services. Franchise fees have no impact on net income. Revenues from other energy services did not have a material effect on net income since they were generally offset by associated expenses.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2016 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2016	**2016**	2015	**2016**	2015
	(in millions)				
Residential	**5,358**	**(0.1)%**	— %	**(0.2)%**	(1.0)%
Commercial	**3,869**	**(0.7)**	1.6	**(1.5)**	0.3
Industrial	**1,830**	**1.8**	(2.8)	**1.8**	(2.8)
Other	**25**	**(0.8)**	(0.1)	**(0.8)**	(0.1)
Total retail	**11,082**	**—**	0.1	**(0.3)%**	(0.8)%
Wholesale					
Non-affiliates	**751**	**(27.8)**	(37.7)		
Affiliates	**2,784**	**46.1**	(42.0)		
Total wholesale	**3,535**	**20.0**	(40.5)		
Total energy sales	**14,617**	**4.2 %**	(12.5)%		

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

Residential KWH sales decreased in 2016 compared to 2015 due to declining use per customer primarily resulting from energy efficiency improvements, partially offset by customer growth and warmer weather during the third quarter. Residential KWH sales increased minimally in 2015 compared to 2014 due to customer growth and warmer weather in the second and third quarters of 2015, mostly offset by a decline in use per customer, primarily resulting from efficiency improvements.

Commercial KWH sales decreased in 2016 compared to 2015 due to declining use per customer, primarily resulting from energy efficiency improvements, partially offset by customer growth and warmer weather during the third quarter. Commercial KWH sales increased in 2015 compared to 2014 due to customer growth and warmer weather in the second and third quarters of 2015, partially offset by a decline in use per customer, primarily resulting from efficiency improvements.

Industrial KWH sales increased in 2016 compared to 2015 primarily due to decreased customer co-generation, partially offset by changes in customers' operations. Industrial KWH sales decreased in 2015 compared to 2014 primarily due to increased customer co-generation as a result of lower natural gas prices, partially offset by increases due to changes in customers' operations.

See "Operating Revenues" above for a discussion of significant changes in wholesale sales to non-affiliates and affiliated companies.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2016 Annual Report

Details of the Company's generation and purchased power were as follows:

	2016	2015	2014
Total generation *(in millions of KWHs)*	**8,259**	8,629	11,109
Total purchased power *(in millions of KWHs)*	**6,973**	5,976	5,547
Sources of generation *(percent)* –			
Coal	**57**	57	67
Gas	**43**	43	33
Cost of fuel, generated *(in cents per net KWH)* –			
Coal	**3.68**	3.88	4.03
Gas	**4.17**	4.22	3.93
Average cost of fuel, generated *(in cents per net KWH)*	**3.89**	4.03	3.99
Average cost of purchased power *(in cents per net KWH)* (*)	**3.63**	3.89	4.83

(*) Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

In 2016 , total fuel and purchased power expenses were $574 million, a decrease of $6 million, or 1.0%, from the prior year costs. The decrease was primarily the result of a $30 million decrease due to a lower average cost of fuel and purchased power, largely offset by a $24 million increase due to a higher volume of KWHs generated and purchased.

In 2015 , total fuel and purchased power expenses were $580 million, a decrease of $132 million, or 18.5%, from the prior year costs. The decrease was primarily the result of a $79 million decrease due to a lower volume of KWHs generated and purchased and a $53 million decrease due to a lower average cost of fuel and purchased power.

Fuel and purchased power transactions do not have a significant impact on earnings since energy and capacity expenses are generally offset by energy and capacity revenues through the Company's fuel and purchased power capacity cost recovery clauses and long-term wholesale contracts. See Note 3 to the financial statements under "Retail Regulatory Matters – Cost Recovery Clauses – Retail Fuel Cost Recovery" and " – Purchased Power Capacity Recovery" for additional information.

Fuel

Fuel expense was $432 million in 2016 , a decrease of $13 million, or 2.9%, from the prior year costs. The decrease was primarily due to a 3.5% decrease in the average cost of fuel due to lower coal and natural gas prices and a 4.3% lower volume of KWHs generated due to an increase in KWHs purchased from lower-cost gas-fired PPA resources. In 2015 , fuel expense was $445 million , a decrease of $160 million, or 26.4%, from the prior year costs. The decrease was primarily due to a 22.3% lower volume of KWHs generated due to the availability of lower-cost generation alternatives, partially offset by a 1.0% increase in the average cost of fuel due to higher natural gas prices per KWH generated.

Purchased Power – Non-Affiliates

Purchased power expense from non-affiliates was $126 million in 2016 , an increase of $26 million, or 26.0%, from the prior year. The increase was primarily due to a 41.2% increase in the volume of KWHs purchased due to an increase in energy purchased from gas-fired PPA resources, partially offset by a 14.9% decrease in the average cost per KWH purchased, both due to lower energy costs from gas-fired resources. In 2015 , purchased power expense from non-affiliates was $100 million , an increase of $18 million, or 22.0%, from the prior year. The increase was primarily due to a $26 million increase in capacity costs associated with a scheduled price increase for an existing PPA, partially offset by the expiration of another PPA, an 11.9% decrease in the average cost per KWH purchased due to lower market prices for fuel, and a 7.8% decrease in the volume of KWHs purchased due to the availability of lower-cost generation alternatives.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation.

Purchased Power – Affiliates

Purchased power expense from affiliates was $16 million in 2016 , a decrease of $19 million, or 54.3%, from the prior year. The decrease was primarily due to a 53.9% decrease in the volume of KWHs purchased primarily due to increased supply from the Company's fossil and wind resources, partially offset by a 0.4% increase in the average cost per KWH purchased from power pool resources. In 2015 , purchased power expense from affiliates was $35 million , an increase of $10 million, or 40.0%, from the prior

year. The increase was primarily due to a 108.9% increase in the volume of KWHs purchased primarily due to the availability of lower-cost generation alternatives available from the power pool, partially offset by a 34.2% decrease in the average cost per KWH purchased due to lower power pool interchange rates.

Energy purchases from affiliates will vary depending on demand and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, all as approved by the FERC.

Other Operations and Maintenance Expenses

In 2016 , other operations and maintenance expenses decreased $18 million, or 5.1%, compared to the prior year primarily due to decreases of $7 million in marketing incentive programs and $6 million in routine and planned maintenance expenses at generation facilities. Also contributing to the decrease was $4 million in rate case expense amortization recorded in 2015 and a $3 million reduction in employee compensation and benefits expenses including pension costs. In 2015 , other operations and maintenance expenses increased $13 million, or 3.8%, compared to the prior year primarily due to increases of $6 million in employee compensation and benefits expenses including pension costs, $3 million in rate case expense amortization, and $2 million in energy service contracts.

Expenses from marketing incentive programs and energy services did not have a significant impact on earnings since they were generally offset by associated revenues. Rate case expenses were amortized as authorized in the 2013 Rate Case Settlement Agreement. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Cost Recovery Clauses" herein and Note 2 to the financial statements for additional information related to rate case expenses and pension costs, respectively.

Depreciation and Amortization

Depreciation and amortization increased $31 million, or 22.0%, in 2016 compared to the prior year. The increase was primarily due to a reduction in depreciation of $20.1 million recorded in 2015, as authorized in the 2013 Rate Case Settlement Agreement, and an increase of $9 million primarily attributable to property additions to utility plant. In 2015 , depreciation and amortization decreased $4 million, or 2.8%, compared to the prior year. As authorized in the 2013 Rate Case Settlement Agreement, the Company recorded $11.7 million more of a reduction in depreciation in 2015 than in 2014. This decrease was partially offset by an increase of $8 million primarily attributable to property additions at transmission and distribution facilities. See Note 3 to the financial statements under "Retail Regulatory Matters – Retail Base Rate Cases" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $2 million, or 1.7%, in 2016 compared to the prior year primarily due to increases of $2 million in property taxes. In 2015 , taxes other than income taxes increased $7 million, or 6.3%, compared to the prior year primarily due to increases of $3 million in property taxes, $2 million in franchise fees, and $2 million in gross receipts taxes. Gross receipts taxes and franchise fees are based on billed revenues and have no impact on net income. These taxes are collected from customers and remitted to governmental agencies.

Total Other Income and (Expense)

In 2016 , total other income and (expense) decreased $11 million, or 26.8%, compared to the prior year primarily due to a decrease of $13 million in AFUDC equity related to environmental control projects at generating facilities and transmission projects placed in service in 2015, partially offset by a $2 million decrease in interest expense, net of amounts capitalized, primarily due to the redemption of debt. In 2015 , total other income and (expense) increased $3 million, or 6.8%, primarily due to $6 million in deferred returns on transmission projects, which reduced interest expense and were recorded as a regulatory asset, as authorized in the 2013 Rate Case Settlement Agreement. This decrease was partially offset by a $2 million net increase in interest expense related to long-term debt resulting from the issuance of senior notes in 2014. See Note 1 to the financial statements under "Allowance for Funds Used During Construction" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located in northwest Florida and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Florida PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and limited projected demand growth over the next several years, and the outcome of the 2016 Rate Case. Future earnings will be driven primarily by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies due to changes in the minimum allowable equipment efficiencies along with the continuation of changes in customer behavior. Earnings are subject to a variety of other factors. These factors include weather, competition, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Demand for electricity is primarily driven by economic growth. The pace of economic growth and electricity demand may be affected by changes in regional and global economic conditions, which may impact future earnings. Current proposals related to potential tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals is dependent on the final form of any legislation enacted and the related transition rules and cannot be determined at this time, but could have a material impact on the Company's financial statements.

Through 2015, long-term non-affiliate capacity sales from the Company's ownership of Plant Scherer Unit 3 provided the majority of the Company's wholesale earnings. Contract expirations at the end of 2015 and the end of May 2016 related to Plant Scherer Unit 3 wholesale sales had a material negative impact on the Company's earnings in 2016. Remaining contract sales from Plant Scherer Unit 3 cover approximately 24% of the Company's ownership of the unit through 2019. The Company has requested recovery through retail rates for the portion of Plant Scherer Unit 3 that has been rededicated to serving retail customers. Therefore, the retail recoverability of these costs will be decided in the 2016 Rate Case. If retail recovery of Plant Scherer Unit 3 is not approved by the Florida PSC in the 2016 Rate Case, the Company may consider an asset sale. The current book value of the Company's ownership of Plant Scherer Unit 3 could exceed market value which could result in a material loss. See Note 3 to the financial statements under "Retail Regulatory Matters – Retail Base Rate Cases" for additional information.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in retail rates or through long-term wholesale agreements on a timely basis or through market-based contracts. The State of Florida has statutory provisions that allow a utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. The Company's current long-term wholesale agreements contain provisions that permit charging the customer with costs incurred as a result of changes in environmental laws and regulations. The full impact of any such legislative or regulatory changes cannot be determined at this time. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are completed. Further, higher costs that are recovered through regulated rates or long-term wholesale agreements could contribute to reduced demand for electricity as well as impact the cost competitiveness of wholesale capacity, which could negatively affect results of operations, cash flows, and financial condition. See "Other Matters" herein and Note 3 to the financial statements under "Environmental Matters" and "Retail Regulatory Matters – Cost Recovery Clauses – Environmental Cost Recovery" for additional information, including a discussion on the State of Florida's statutory provisions on environmental cost recovery.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; the Migratory Bird Treaty Act; the Bald and Golden Eagle Protection Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2016 , the Company had invested approximately $1.9 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $28 million, $116 million, and $227 million for 2016 , 2015 , and 2014 , respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $245 million from 2017 through 2021 , with annual totals of approximately $33 million, $52 million, $57 million, $55 million, and $48 million for 2017 , 2018 , 2019 , 2020 , and 2021 , respectively. These estimated expenditures do not include any potential capital expenditures that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from existing, new, modified, or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Company also anticipates costs associated with ash pond closure and ground water monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule) and the closure of an ash pond at Plant Scholz, which are reflected in the Company's ARO liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Cost of Removal" for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations, including the environmental regulations described below; the time periods over which compliance with regulations is required; individual state implementation of regulations, as applicable; the outcome of any legal challenges to the environmental rules; any additional rulemaking activities in response to legal challenges and court decisions; the cost, availability, and existing inventory of emissions allowances; the impact of future changes in generation and emissions-related technology; the Company's fuel mix; and environmental remediation requirements. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time.

Compliance with any new federal or state legislation or regulations relating to air, water, and land resources or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the Company's commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company.

In 2012, the EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. The implementation strategy for the MATS rule included emission controls, retirements, and fuel conversions at affected units. All of the Company's units that are subject to the MATS rule completed the measures necessary to achieve compliance with this rule or were retired prior to or during 2016.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard (NAAQS). In 2008, the EPA adopted a revised eight-hour ozone NAAQS and published its final area designations in 2012. All areas within the Company's service territory have achieved attainment of the 2008 standard. In October 2015, the EPA published a more stringent eight-hour ozone NAAQS. This new standard could potentially require additional emission controls, improvements in control efficiency, and operational fuel changes and could affect the siting of new generating facilities. States were required to recommend area designations by October 2016, and no areas within the Company's service territory were proposed for designation as nonattainment.

The EPA regulates fine particulate matter concentrations through an annual and 24-hour average NAAQS, based on standards promulgated in 1997, 2006, and 2012. All areas in which the Company's generating units are located have been determined by the EPA to be in attainment with those standards.

In 2010, the EPA revised the NAAQS for sulfur dioxide (SO_2) , establishing a new one-hour standard. No areas within the Company's service territory have been designated as nonattainment under this standard. However, in 2015, the EPA finalized a data requirements rule to support final EPA designation decisions for all remaining areas under the SO_2 standard, which could result in nonattainment designations for areas within the Company's service territory. Nonattainment designations could require additional reductions in SO_2 emissions and increased compliance and operational costs.

On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide (NO_x) emissions from power plants in two phases – Phase 1 in 2015 and Phase 2 in 2017. On October 26, 2016, the EPA published a final rule that updates the CSAPR ozone-season NO_x program, beginning in 2017, and establishes more stringent ozone-season emissions budgets in Mississippi and removes Florida from the program. The State of Georgia's emission budget was not affected by the revisions, but interstate emissions trading is restricted unless the state decides to voluntarily adopt a significantly reduced budget. Georgia is also in the CSAPR annual SO_2 and NO_x programs.

The EPA finalized regional haze regulations in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology to certain sources, including fossil fuel-fired generating facilities, built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter. On December 14, 2016, the EPA finalized revisions to the regional haze regulations. These regulations establish a deadline of July 31, 2021 for states to submit revised State Implementation Plans (SIP) to the EPA demonstrating reasonable progress toward the statutory goal of achieving natural background conditions by 2064. State implementation of the reasonable progress requirements defined in this final rule could require further reductions in SO_2 or NO_x emissions.

In June 2015, the EPA published a final rule requiring certain states (including Florida, Georgia, and Mississippi) to revise or remove the provisions of their SIPs relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM), and proposed SIP revisions have been submitted by the affected states where the Company's generating units are located.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. These regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates or through PPAs. The ultimate impact of the eight-hour ozone and SO_2 NAAQS, CSAPR, regional haze regulations, and SSM rule will depend on various factors, such as implementation, adoption, or other action at the state level, and the outcome of pending and/or future legal challenges, and cannot be determined at this time.

Water Quality

The EPA's final rule establishing standards for reducing effects on fish and other aquatic life caused by new and existing cooling water intake structures at existing power plants and manufacturing facilities became effective in 2014. The effect of this final rule will depend on the results of additional studies that are currently underway and implementation of the rule by regulators based on site-specific factors. National Pollutant Discharge Elimination System (NPDES) permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule.

In November 2015, the EPA published a final effluent guidelines rule which imposes stringent technology-based requirements for certain wastestreams from steam electric power plants. The revised technology-based limits and compliance dates will be incorporated into future renewals of NPDES permits at affected units and may require the installation and operation of multiple technologies sufficient to ensure compliance with applicable new numeric wastewater compliance limits. Compliance deadlines between November 1, 2018 and December 31, 2023 will be established in permits based on information provided for each applicable wastestream.

In 2015, the EPA and the U.S. Army Corps of Engineers jointly published a final rule revising the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs. The final rule significantly expands the scope of federal jurisdiction under the CWA and could have significant impacts on economic development projects which could affect customer demand growth. In addition, this rule could significantly increase permitting and regulatory requirements and costs associated with the siting of new facilities and the installation, expansion, and maintenance of transmission and distribution lines . The rule became effective in August 2015 but, in October 2015, the U.S. Court of Appeals for the Sixth Circuit issued an order staying implementation of the final rule. The case is held in abeyance pending review by the U.S. Supreme Court of challenges to the U.S. Court of Appeals for the Sixth Circuit's jurisdiction in the case.

In addition, numeric nutrient water quality standards promulgated by the State of Florida to limit the amount of nitrogen and phosphorous allowed in state waters are in effect for the State's streams and estuaries. The impact of these standards will depend on further regulatory action in connection with their site-specific implementation through the State of Florida's National Pollutant Discharge Elimination System permitting program and Total Maximum Daily Load restoration program and cannot be determined at this time.

These water quality regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions and decisions on infrastructure expansion and improvements. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through PPAs. The ultimate impact of these final rules will depend on various factors, such as pending and/or future legal challenges, compliance dates, and implementation of the rules, and cannot be determined at this time.

Coal Combustion Residuals

The Company currently manages CCR at onsite storage units consisting of landfills and surface impoundments (CCR Units) at three electric generating plants in Florida and is a co-owner of units at generating plants located in Mississippi and Georgia operated by Mississippi Power and Georgia Power, respectively. In addition to on-site storage, the Company sells a portion of its CCR to third parties for beneficial reuse. Individual states regulate CCR and the States of Florida, Mississippi, and Georgia each have their own regulatory requirements. The Company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

The CCR Rule became effective in October 2015. The CCR Rule regulates the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in CCR Units at active generating power plants. The CCR Rule does not automatically require closure of CCR Units but includes minimum criteria for active and inactive surface impoundments containing CCR and liquids, lateral expansions of existing units, and active landfills. Failure to meet the minimum criteria can result in the required closure of a CCR Unit. On December 16, 2016, President Obama signed the Water Infrastructure Improvements for the Nation Act (WIIN Act). The WIIN Act allows states to establish permit programs for implementing the CCR Rule, if the EPA approves the program, and allows for federal permits and EPA enforcement where a state permitting program does not exist.

Based on current cost estimates for closure and monitoring of ash ponds pursuant to the CCR Rule, and the closure of an ash pond at Plant Scholz, the Company has recorded AROs. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing with respect to compliance activities, the Company expects to continue to periodically update these estimates. The Company has posted closure and post-closure care plans to its public website as required by the CCR Rule; however, the ultimate impact of the CCR Rule will depend on the results of initial and ongoing minimum criteria assessments and the implementation of state or federal permit programs. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The estimated costs associated with closure of the ash ponds at Plant Scholz and Plant Smith for 2017 have been approved for recovery through the environmental cost recovery clause. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information regarding the Company's AROs as of December 31, 2016.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up affected sites. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known affected sites. Included in this amount are costs associated with remediation of the Company's substation sites. These projects have been approved by the Florida PSC for recovery through the environmental cost recovery clause; therefore, these liabilities have no impact to the Company's net income. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

In October 2015, the EPA published two final actions that would limit CO_2 emissions from fossil fuel-fired electric generating units. One of the final actions contains specific emission standards governing CO_2 emissions from new, modified, and reconstructed units. The other final action, known as the Clean Power Plan, establishes guidelines for states to develop plans to meet EPA-mandated CO_2 emission rates or emission reduction goals for existing units. The EPA's final guidelines require state plans to meet interim CO_2 performance rates between 2022 and 2029 and final rates in 2030 and thereafter. At the same time, the EPA published a proposed federal plan and model rule that, when finalized, states can adopt or that would be put in place if a state

either does not submit a state plan or its plan is not approved by the EPA. On February 9, 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan, pending disposition of petitions for review with the courts. The stay will remain in effect through the resolution of the litigation, including any review by the U.S. Supreme Court.

These guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions and decisions on infrastructure expansion and improvements . The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through PPAs. However, the ultimate financial and operational impact of the final rules on the Company cannot be determined at this time and will depend upon numerous factors, including the outcome of pending legal challenges, including legal challenges filed by the traditional electric operating companies, and any individual state implementation of the EPA's final guidelines in the event the rule is upheld and implemented.

In December 2015, parties to the United Nations Framework Convention on Climate Change – including the United States – adopted the Paris Agreement, which establishes a non-binding universal framework for addressing greenhouse gas emissions based on nationally determined contributions. It also sets in place a process for tracking progress toward the goals every five years. The ultimate impact of this agreement depends on its implementation by participating countries and cannot be determined at this time.

The EPA's greenhouse gas reporting rule requires annual reporting of greenhouse gas emissions expressed in terms of metric tons of CO_2 equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2015 greenhouse gas emissions were approximately 9 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2016 greenhouse gas emissions on the same basis is approximately 8 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation, the mix of fuel sources, and other factors.

FERC Matters

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric operating companies' (including the Company's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies (including the Company) and Southern Power filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.

On December 9, 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. The traditional electric operating companies (including the Company) and Southern Power expect to make a compliance filing within 30 days accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

The ultimate outcome of these matters cannot be determined at this time.

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

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Retail Base Rate Cases

In 2013, the Florida PSC approved the 2013 Rate Case Settlement Agreement among the Company and all of the intervenors to the Company's retail base rate case. Under the terms of the 2013 Rate Case Settlement Agreement, the Company (1) increased base rates approximately $35 million and $20 million annually effective January 2014 and 2015, respectively; (2) continued its authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); (3) may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017, of which $28.5 million had been recorded as of December 31, 2016; and (4) accrued a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 through January 1, 2017.

The 2013 Rate Case Settlement Agreement also provides that the Company may reduce depreciation and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million from January 2014 through June 2017. In any given month, such depreciation reduction may not exceed the amount necessary for the retail ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized retail ROE range then in effect. Recovery of the regulatory asset will occur over a period to be determined by the Florida PSC in the Company's 2016 Rate Case. For 2014 and 2015, the Company recognized reductions in depreciation expense of $8.4 million and $20.1 million , respectively. No net reduction in depreciation was recorded in 2016.

On October 12, 2016, the Company filed the 2016 Rate Case with the Florida PSC requesting an annual increase in retail rates and charges of $106.8 million based on the projected test year of January 1, 2017 through December 31, 2017 and a retail ROE of 11% compared to the current retail ROE of 10.25%. The requested increase includes recovery of the portion of Plant Scherer Unit 3 that has been rededicated to serving retail customers following the contract expirations discussed previously. If retail recovery of Plant Scherer Unit 3 is not approved by the Florida PSC in the 2016 Rate Case, the Company may consider an asset sale. The current book value of the Company's ownership of Plant Scherer Unit 3 could exceed market value which could result in a material loss. The Florida PSC is expected to make a decision on the 2016 Rate Case in the second quarter 2017. The Company has requested that the increase in base rates, if approved by the Florida PSC, become effective in July 2017. The ultimate outcome of this matter cannot be determined at this time.

See Note 3 to the financial statements under "Retail Regulatory Matters – Retail Base Rate Cases" for additional information.

Cost Recovery Clauses

On November 2, 2016, the Florida PSC approved the Company's 2017 annual cost recovery clause rates for its fuel, purchased power capacity, environmental, and energy conservation cost recovery clauses. The net effect of the approved changes is a decrease of approximately $41 million in annual revenues effective in January 2017. In general, the decreased revenues will not have a significant impact on net income since most of the revenues will be offset by lower expenses. However, certain costs associated with the ongoing ownership and operation of Plant Scherer Unit 3 were included in the environmental cost recovery clause rate, which increased annual revenues by approximately $12 million in 2016 and is expected to increase revenues by an incremental $2 million for a total of approximately $14 million in 2017. The final disposition of these costs, and the related impact on rates, is subject to the Florida PSC's ultimate ruling on whether costs associated with Plant Scherer Unit 3 are recoverable from retail customers, which is expected to be decided in the 2016 Rate Case as discussed previously. The ultimate outcome of this matter cannot be determined at this time. See Note 3 to the financial statements under "Retail Regulatory Matters – Retail Base Rate Cases" for additional information.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment. See Note 1 to the financial statements under "Revenues" for additional information.

Renewables

In April 2015, the Florida PSC approved three energy purchase agreements totaling 120 MWs of utility-scale solar generation located at three military installations in northwest Florida. Purchases under these solar agreements are expected to begin by the summer of 2017.

The Florida PSC issued a final approval order on the Company's Community Solar Pilot Program on April 15, 2016. The program will offer the Company's customers an opportunity to voluntarily contribute to the construction and operation of a solar photovoltaic facility with electric generating capacity of up to 1 MW through annual subscriptions. The energy generated from the solar facility is expected to provide power to all of the Company's customers.

On November 29, 2016, the Florida PSC approved an energy purchase agreement for up to 94 MWs of additional wind generation in central Oklahoma. Purchases under this agreement will be for energy only and will be recovered through the Company's fuel cost recovery clause.

Income Tax Matters

Bonus Depreciation

In December 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service through 2020. The PATH Act allows for 50% bonus depreciation for 2015 through 2017, 40% bonus depreciation for 2018, and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. The extension of bonus depreciation included in the PATH Act is expected to result in approximately $20 million of positive cash flows for the 2016 tax year and approximately $26 million for the 2017 tax year. See Note 5 to the financial statements for additional information.

Other Matters

As a result of the cost to comply with environmental regulations imposed by the EPA, the Company retired its coal-fired generation at Plant Smith Units 1 and 2 (357 MWs) on March 31, 2016. The Company filed a petition with the Florida PSC requesting permission to recover the remaining net book value of Plant Smith Units 1 and 2 and the remaining materials and supplies associated with these units as of the retirement date. On August 29, 2016, the Florida PSC approved the Company's request to reclassify these costs, totaling approximately $63 million, to a regulatory asset for recovery over a period to be decided in the 2016 Rate Case. The ultimate outcome of this matter cannot be determined at this time.

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Utility Regulation

The Company is subject to retail regulation by the Florida PSC. The Florida PSC sets the rates the Company is permitted to charge customers based on allowable costs. The Company is also subject to cost-based regulation by the FERC with respect to wholesale transmission rates. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and 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.

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As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Asset Retirement Obligations

AROs are computed as the fair value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities.

The liability for AROs primarily relates to the Company's facilities that are subject to the CCR Rule and to the closure of an ash pond at Plant Scholz. In addition, the Company has retirement obligations related to combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO.

The Company recorded new AROs in 2015 for facilities that are subject to the CCR Rule as discussed above and for the closure of an ash pond at Plant Scholz. The cost estimates are based on information using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure for those facilities impacted by the CCR Rule. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing with respect to compliance activities, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the Company expects to continue to periodically update these estimates. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Coal Combustion Residuals" herein for additional information.

Given the significant judgment involved in estimating AROs, the Company considers the liabilities for AROs to be critical accounting estimates.

See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, the Company discounts the future related cash flows using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. For 2015 and prior years, the Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. For 2016, the Company adopted

a full yield curve approach for calculating the interest cost component whereby the discount rate for each year is applied to the liability for that specific year. As a result, the interest cost component of net periodic pension and other postretirement benefit plan expense decreased by approximately $4 million in 2016.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $2 million or less change in total annual benefit expense and a $21 million or less change in projected obligations.

See Note 2 to the financial statements for additional information regarding pension and other postretirement benefits.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's results of operations, cash flows, or financial condition.

Recently Issued Accounting Standards

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers,* replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

While the Company expects most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of such arrangements. The majority of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term. For such arrangements, the Company generally expects that the revenue from contracts with these customers will continue to be equivalent to the electricity supplied and billed in that period (including unbilled revenues) and the adoption of ASC 606 will not result in a significant shift in the timing of revenue recognition for such sales.

The Company's ongoing evaluation of other revenue streams and related contracts includes longer term contractual commitments and unregulated sales to customers. Some revenue arrangements, such as certain PPAs and alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on the Company's financial statements. In addition, the power and utilities industry is currently addressing other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). If final implementation guidance indicates CIAC will be accounted for under ASC 606 and offsetting regulatory treatment is not permitted, it could have a material impact on the Company's financial statements.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. The Company must select a transition method to be applied either retrospectively to each prior reporting period presented or retrospectively with a cumulative effect adjustment to retained earnings at the date of initial adoption. As the ultimate impact of the new standard has not yet been determined, the Company has not elected its transition method.

On February 25, 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged . ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company is currently evaluating the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

On March 30, 2016, the FASB issued ASU No. 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities

rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5, 8, and 11 to the financial statements for disclosures impacted by ASU 2016-09.

On October 24, 2016, the FASB issued ASU No. 2016-16, *Income Taxes (Topic 740), Intra-Entity Transfers of Assets Other Than Inventory* (ASU 2016-16). Current GAAP prohibits the recognition of current and deferred income taxes for an affiliate asset transfer until the asset has been sold to an outside party. ASU 2016-16 requires an entity to recognize the income tax consequences of an affiliate transfer of an asset other than inventory when the transfer occurs. ASU 2016-16 is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. The amendments will be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The Company is currently assessing the impact of the standard on its financial statements and has not yet determined its ultimate impact.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2016 . The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to maintain existing 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 2017 through 2019 , the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt issuances in the capital markets, borrowings from financial institutions, and equity contributions from Southern Company. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit agreements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan increased in value as of December 31, 2016 as compared to December 31, 2015 . On December 19, 2016, the Company voluntarily contributed $48 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated during 2017 . See Note 2 to the financial statements under "Pension Plans" for additional information.

Net cash provided from operating activities totaled $379 million in 2016 , a decrease of $81 million from 2015 , primarily due to decreases in cash flows related to clause recovery and a voluntary contribution to the qualified pension plan, partially offset by the timing of fossil fuel stock purchases. Net cash provided from operating activities totaled $460 million in 2015 , an increase of $116 million from 2014 , primarily due to increases in cash flows related to clause recovery and bonus depreciation. This increase was partially offset by decreases related to the timing of fossil fuel stock purchases and vendor payments.

Net cash used for investing activities totaled $180 million , $281 million , and $358 million for 2016 , 2015 , and 2014 , respectively. The changes in cash used for investing activities were primarily related to gross property additions for environmental, distribution, steam generation, and transmission assets. Funds for the Company's property additions were provided by operating activities, capital contributions, and other financing activities.

Net cash used for financing activities totaled $217 million in 2016 primarily due to the redemptions of long-term debt and the payment of common stock dividends, partially offset by an increase in notes payable. Net cash used for financing activities totaled $144 million in 2015 primarily due to the payment of common stock dividends and redemptions of long-term debt, partially offset by an increase in notes payable and proceeds from the issuance of common stock to Southern Company. Net cash provided from financing activities totaled $31 million in 2014 primarily due to the issuance of long-term debt and common stock to Southern Company, partially offset by the payment of common stock dividends, the redemption of long-term debt, and a decrease to notes payable. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2016 included a decrease of $206 million in long-term debt due to the early retirement and redemption at maturity of $235 million in senior notes and the reclassification of $85 million in senior notes to securities due within one year, an increase of $126 million in notes payable, and an increase of $85 million in other regulatory assets, deferred,

primarily related to the retirement of Plant Smith Units 1 and 2 and CCR compliance costs. See Note 3 to the financial statements for additional information related to the retirement of Plant Smith Units 1 and 2.

The Company's ratio of common equity to total capitalization plus short-term debt, was 48.3% and 46.0% at December 31, 2016 and 2015 , respectively. See Note 6 to the financial statements for additional information.

Sources of Capital

The Company plans to obtain the funds required to meet its future capital needs from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, external security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors.

Security issuances are subject to annual regulatory approval by the Florida PSC pursuant to its rules and regulations. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Florida PSC, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as significant seasonal fluctuations in cash needs. The Company has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet short-term liquidity needs, including its commercial paper program which is supported by bank credit facilities.

At December 31, 2016 , the Company had approximately $56 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2016 were as follows:

Expires				Executable Term Loans		Expires Within One Year	
2017	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)		*(in millions)*		*(in millions)*		*(in millions)*	
$85	$195	$280	$280	$45	$—	$25	$60

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Most of these bank credit arrangements contain covenants that limit debt levels and contain cross acceleration provisions to other indebtedness (including guarantee obligations) of the Company. Such cross acceleration provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2016 , the Company was in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

Subject to applicable market conditions, the Company expects to renew or replace its bank credit arrangements, as needed, prior to expiration. In connection therewith, the Company may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

Most of the unused credit arrangements with banks are allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2016 was approximately $82 million. In addition, at December 31, 2016 , the Company had $86 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional 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. Short-term borrowings are included in notes payable in the balance sheets.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (*)		
	Amount Outstanding	Weighted Average Interest Rate	Average Amount Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2016					
Commercial paper	**$ 168**	**1.1%**	**$ 53**	**0.9%**	**$ 168**
Short-term bank debt	**100**	**1.5%**	**64**	**1.3%**	**100**
Total	**$ 268**	**1.2%**	**$ 117**	**1.1%**	
December 31, 2015					
Commercial paper	$ 142	0.7%	$ 101	0.4%	$ 175
Short-term bank debt	—	—%	10	0.7%	40
Total	$ 142	0.7%	$ 111	0.4%	
December 31, 2014					
Commercial paper	$ 110	0.3%	$ 85	0.2%	$ 145

(*) Average and maximum amounts are based upon daily balances during the year.

The Company believes the need for working capital can be adequately met by utilizing the commercial paper program, lines of credit, short-term bank term loans, and operating cash flows.

Financing Activities

In May 2016, the Company redeemed $125 million aggregate principal amount of its Series 2011A 5.75% Senior Notes due June 1, 2051.

Also in May 2016, the Company entered into an 11-month floating rate bank loan bearing interest based on one-month LIBOR. This short-term loan was for $100 million aggregate principal amount and the proceeds were used to repay existing indebtedness and for working capital and other general corporate purposes.

In December 2016, the Company repaid at maturity $110 million aggregate principal amount of its Series M 5.30% Senior Notes due December 1, 2016.

Subsequent to December 31, 2016, the Company issued 1,750,000 shares of common stock to Southern Company and realized proceeds of $175 million . 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, contractual obligations, and storm recovery, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Credit Rating Risk

At December 31, 2016, the Company did not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, transmission, and energy price risk management.

The maximum potential collateral requirements under these contracts at December 31, 2016 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements	
	(in millions)	
At BBB- and/or Baa3	$	192
Below BBB- and/or Baa3	$	628

Included in these amounts are certain agreements that could require collateral in the event that Alabama Power or Georgia Power has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of the Company to access capital markets and would be likely to impact the cost at which it does so.

On January 10, 2017, S&P revised its consolidated credit rating outlook for Southern Company (including the Company) from negative to stable.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives which are designated as hedges. The weighted average interest rate on $82 million of outstanding variable rate long-term debt that has not been hedged at January 1, 2017 was 0.79%. If the Company sustained a 100 basis point change in interest rates for all variable rate long-term debt, the change would not materially affect annualized interest expense at January 1, 2017. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to movements in fuel and electricity prices, the Company enters into financial hedge contracts for natural gas purchases and physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. The Company continues to manage a fuel-hedging program implemented per the guidelines of the Florida PSC and the actual cost of fuel is recovered through the retail fuel clause. The Florida PSC approved a stipulation and agreement that prospectively imposed a moratorium on the Company's fuel-hedging program in October 2016 through December 31, 2017. The Company had no material change in market risk exposure for the year ended December 31, 2016 when compared to the year ended December 31, 2015 .

The changes in fair value of energy-related derivative contracts are substantially attributable to both the volume and the price of natural gas. For the years ended December 31, the changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, were as follows:

	2016 Changes		2015 Changes	
	Fair Value			
	(in millions)			
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$**	**(100)**	$	(72)
Contracts realized or settled		**49**		47
Current period changes (*)		**27**		(75)
Contracts outstanding at the end of the period, assets (liabilities), net	**$**	**(24)**	$	(100)

(*) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The net hedge volumes of energy-related derivative contracts were 51 million mmBtu and 82 million mmBtu as of December 31, 2016 and December 31, 2015 , respectively.

The weighted average swap contract cost above market prices was approximately $0.48 per mmBtu as of December 31, 2016 and $1.17 per mmBtu as of December 31, 2015 . Natural gas settlements are recovered through the Company's fuel cost recovery clause.

At December 31, 2016 and 2015 , substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery clause. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented and the actual cost of fuel is recovered through the retail fuel clause. The moratorium imposed by the Florida PSC does not have an impact on the recovery of existing hedges entered into under the previously-approved hedging program.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2 of the fair value hierarchy. See Note 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2016 were as follows:

	Fair Value Measurements December 31, 2016			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ —	$ —	$ —	$ —
Level 2	(24)	(8)	(16)	—
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ (24)	$ (8)	$ (16)	$ —

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P, or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements.

Through 2015, long-term non-affiliate capacity sales from the Company's ownership of Plant Scherer Unit 3 provided the majority of the Company's wholesale earnings. Contract expirations at the end of 2015 and the end of May 2016 related to Plant Scherer Unit 3 wholesale sales had a material negative impact on the Company's earnings in 2016. Remaining contract sales from Plant Scherer Unit 3 cover approximately 24% of the Company's ownership of the unit through 2019. The Company has requested recovery through retail rates for the portion of Plant Scherer Unit 3 that has been rededicated to serving retail customers. Therefore, the retail recoverability of these costs will be decided in the 2016 Rate Case. If retail recovery of Plant Scherer Unit 3 is not approved by the Florida PSC in the 2016 Rate Case, the Company may consider an asset sale. The current book value of the Company's ownership of Plant Scherer Unit 3 could exceed market value which could result in a material loss. See Note 3 to the financial statements under "Retail Regulatory Matters – Retail Base Rate Cases" for additional information.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to total $227 million for 2017 , $218 million for 2018 , $219 million for 2019 , $265 million for 2020 , and $225 million for 2021 . These amounts include capital expenditures related to contractual purchase commitments for capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these amounts are $33 million, $52 million, $57 million, $55 million, and $48 million for 2017 , 2018 , 2019 , 2020 , and 2021 , respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from new, existing, modified, or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and "– Global Climate Issues" herein for additional information.

The Company also anticipates costs associated with closure and monitoring of ash ponds at Plant Scholz and 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 $16 million, $17 million, $6 million, $26 million, and $8 million for the years 2017 , 2018 , 2019 , 2020 , and 2021 , respectively. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing generating units, to meet regulatory requirements; changes in the expected environmental compliance program; changes in FERC rules and regulations; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC and the Florida PSC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Contractual Obligations

Contractual obligations at December 31, 2016 were as follows:

	2017	2018-2019	2020-2021	After 2021	Total
			(in millions)		
Long-term debt [(a)] –					
Principal	$ 87	$ —	$ 175	$ 824	$ 1,086
Interest	42	73	65	515	695
Financial derivative obligations [(b)]	12	17	—	—	29
Preference stock dividends [(c)]	9	18	18	—	45
Operating leases [(d)]	8	7	—	1	16
Purchase commitments –					
Capital [(e)]	227	437	462	—	1,126
Fuel [(f)]	261	290	162	70	783
Purchased power [(g)]	126	261	271	1,044	1,702
Other [(h)]	8	24	34	136	202
Pension and other postretirement benefit plans [(i)]	5	11	—	—	16
Total	$ 785	$ 1,138	$ 1,187	$ 2,590	$ 5,700

(a) All amounts are reflected based on final maturity dates. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 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.

(b) Includes derivative liabilities related to cash flow hedges of forecasted debt, as well as energy-related derivatives. For additional information, see Notes 1 and 10 to the financial statements.

(c) Preference stock does not mature; therefore, amounts are provided for the next five years only.

(d) Excludes a PPA accounted for as a lease, which is 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 capital expenditures covered under long-term service agreements, which are reflected in "Other." At December 31, 2016, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

(f) Includes commitments to purchase coal and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2016.

(g) The capacity and transmission related costs associated with PPAs are recovered through the purchased power capacity clause. Energy costs associated with PPAs are recovered through the fuel clause. See Notes 3 and 7 to the financial statements for additional information.

(h) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices. Limestone costs are recovered through the environmental cost recovery clause. See Note 3 to the financial statements for additional information.

(i) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2016 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, customer and sales growth, economic conditions, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan and postretirement benefit plans contributions, financing activities, start and completion of construction projects, filings with state and federal regulatory authorities, impact of the PATH Act, federal income tax benefits, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws regulating emissions, discharges, and disposal to air, water, and land , and also changes in tax and other laws and regulations to which the Company is subject, including potential tax reform legislation, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries ;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any environmental performance standards ;
- investment performance of the Company's employee and retiree benefit plans ;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on 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.

STATEMENTS OF INCOME
For the Years Ended December 31, 2016 , 2015 , and 2014
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	2016	2015	2014
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 1,281**	$ 1,249	$ 1,267
Wholesale revenues, non-affiliates	**61**	107	129
Wholesale revenues, affiliates	**75**	58	130
Other revenues	**68**	69	64
Total operating revenues	**1,485**	1,483	1,590
Operating Expenses:			
Fuel	**432**	445	605
Purchased power, non-affiliates	**126**	100	82
Purchased power, affiliates	**16**	35	25
Other operations and maintenance	**336**	354	341
Depreciation and amortization	**172**	141	145
Taxes other than income taxes	**120**	118	111
Total operating expenses	**1,202**	1,193	1,309
Operating Income	**283**	290	281
Other Income and (Expense):			
Interest expense, net of amounts capitalized	**(47)**	(49)	(53)
Other income (expense), net	**(5)**	8	9
Total other income and (expense)	**(52)**	(41)	(44)
Earnings Before Income Taxes	**231**	249	237
Income taxes	**91**	92	88
Net Income	**140**	157	149
Dividends on Preference Stock	**9**	9	9
Net Income After Dividends on Preference Stock	**$ 131**	$ 148	$ 140

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2016 , 2015 , and 2014
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	2016	2015	2014
		(in millions)	
Net Income	**$ 140**	$ 157	$ 149
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $-, and $-, respectively	**1**	1	—
Total other comprehensive income (loss)	**1**	1	—
Comprehensive Income	**$ 141**	$ 158	$ 149

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2016 , 2015 , and 2014
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	2016	2015	2014
		(in millions)	
Operating Activities:			
Net income	**$ 140**	$ 157	$ 149
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**179**	152	153
Deferred income taxes	**57**	90	65
Pension and postretirement funding	**(48)**	—	(30)
Other, net	**(3)**	4	(4)
Changes in certain current assets and liabilities —			
-Receivables	**15**	33	(17)
-Fossil fuel stock	**37**	(6)	34
-Prepaid income taxes	**(11)**	32	(19)
-Other current assets	**(1)**	(2)	(2)
-Accounts payable	**5**	(22)	8
-Over recovered regulatory clause revenues	**1**	22	—
-Other current liabilities	**8**	—	7
Net cash provided from operating activities	**379**	460	344
Investing Activities:			
Property additions	**(178)**	(235)	(348)
Cost of removal net of salvage	**(9)**	(10)	(13)
Change in construction payables	**13**	(28)	12
Payments pursuant to long-term service agreements	**(5)**	(8)	(8)
Other investing activities	**(1)**	—	(1)
Net cash used for investing activities	**(180)**	(281)	(358)
Financing Activities:			
Increase (decrease) in notes payable, net	**126**	32	(26)
Proceeds —			
Common stock issued to parent	**—**	20	50
Capital contributions from parent company	**20**	4	4
Pollution control revenue bonds	**—**	13	42
Senior notes	**—**	—	200
Redemptions and repurchases —			
Senior notes	**(235)**	(60)	(75)
Pollution control revenue bonds	**—**	(13)	(29)
Payment of common stock dividends	**(120)**	(130)	(123)
Other financing activities	**(8)**	(10)	(12)
Net cash provided from (used for) financing activities	**(217)**	(144)	31
Net Change in Cash and Cash Equivalents	**(18)**	35	17
Cash and Cash Equivalents at Beginning of Year	**74**	39	22
Cash and Cash Equivalents at End of Year	**$ 56**	$ 74	$ 39
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $-, $6, and $5 capitalized, respectively)	**$ 53**	$ 52	$ 48
Income taxes (net of refunds)	**21**	(7)	44
Noncash transactions — accrued property additions at year-end	**33**	20	42

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2016 and 2015
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Assets	2016	2015
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 56**	$ 74
Receivables —		
Customer accounts receivable	**72**	76
Unbilled revenues	**55**	54
Under recovered regulatory clause revenues	**17**	20
Income taxes receivable, current	**—**	27
Other accounts and notes receivable	**6**	9
Affiliated	**17**	1
Accumulated provision for uncollectible accounts	**(1)**	(1)
Fossil fuel stock	**71**	108
Materials and supplies	**55**	56
Prepaid expenses	**18**	8
Other regulatory assets, current	**44**	90
Other current assets	**12**	14
Total current assets	**422**	536
Property, Plant, and Equipment:		
In service	**5,140**	5,045
Less accumulated provision for depreciation	**1,382**	1,296
Plant in service, net of depreciation	**3,758**	3,749
Other utility plant, net	**—**	62
Construction work in progress	**51**	48
Total property, plant, and equipment	**3,809**	3,859
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**58**	61
Other regulatory assets, deferred	**512**	427
Other deferred charges and assets	**21**	37
Total deferred charges and other assets	**591**	525
Total Assets	**$ 4,822**	$ 4,920

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2016 and 2015
Gulf Power Company 2016 Annual Report

Liabilities and Stockholder's Equity	**2016**	2015
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 87**	$ 110
Notes payable	**268**	142
Accounts payable —		
Affiliated	**59**	55
Other	**54**	44
Customer deposits	**35**	36
Accrued taxes —		
Accrued income taxes	**1**	4
Other accrued taxes	**19**	9
Accrued interest	**8**	9
Accrued compensation	**40**	36
Deferred capacity expense, current	**22**	22
Other regulatory liabilities, current	**16**	22
Liabilities from risk management activities	**9**	49
Other current liabilities	**31**	29
Total current liabilities	**649**	567
Long-Term Debt (See accompanying statements)	**987**	1,193
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**948**	893
Employee benefit obligations	**96**	129
Deferred capacity expense	**119**	141
Asset retirement obligations	**120**	113
Other cost of removal obligations	**249**	233
Other regulatory liabilities, deferred	**47**	47
Other deferred credits and liabilities	**71**	102
Total deferred credits and other liabilities	**1,650**	1,658
Total Liabilities	**3,286**	3,418
Preference Stock (See accompanying statements)	**147**	147
Common Stockholder's Equity (See accompanying statements)	**1,389**	1,355
Total Liabilities and Stockholder's Equity	**$ 4,822**	$ 4,920
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CAPITALIZATION
At December 31, 2016 and 2015
Gulf Power Company 2016 Annual Report

	2016	2015	2016	2015
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
5.30% due 2016	**$ —**	$ 110		
2.93 to 5.90% due 2017	**87**	85		
4.75% due 2020	**175**	175		
3.10% to 5.75% due 2022-2051	**515**	640		
Total long-term notes payable	**777**	1,010		
Other long-term debt —				
Pollution control revenue bonds —				
1.15% to 4.45% due 2022-2049	**227**	227		
Variable rates (0.75% to 0.84% at 1/1/17) due 2022-2042	**82**	82		
Total other long-term debt	**309**	309		
Unamortized debt discount	**(5)**	(8)		
Unamortized debt issuance expense	**(7)**	(8)		
Total long-term debt (annual interest requirement — $42 million)	**1,074**	1,303		
Less amount due within one year	**87**	110		
Long-term debt excluding amount due within one year	**987**	1,193	**39.1%**	44.3%
Preferred and Preference Stock:				
Authorized — 20,000,000 shares — preferred stock				
— 10,000,000 shares — preference stock				
Outstanding — $100 par or stated value				
— 6% preference stock — 550,000 shares (non-cumulative)	**54**	54		
— 6.45% preference stock — 450,000 shares (non-cumulative)	**44**	44		
— 5.60% preference stock — 500,000 shares (non-cumulative)	**49**	49		
Total preference stock (annual dividend requirement — $9 million)	**147**	147	**5.8**	5.4
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 20,000,000 shares				
Outstanding — 5,642,717 shares	**503**	503		
Paid-in capital	**589**	567		
Retained earnings	**296**	285		
Accumulated other comprehensive loss	**1**	—		
Total common stockholder's equity	**1,389**	1,355	**55.1**	50.3
Total Capitalization	**$ 2,523**	$ 2,695	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2016 , 2015 , and 2014
Gulf Power Company 2016 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
				(in millions)		
Balance at December 31, 2013	5	$ 433	$ 553	$ 250	$ (1)	$ 1,235
Net income after dividends on preference stock	—	—	—	140	—	140
Issuance of common stock	—	50	—	—	—	50
Capital contributions from parent company	—	—	7	—	—	7
Cash dividends on common stock	—	—	—	(123)	—	(123)
Balance at December 31, 2014	5	483	560	267	(1)	1,309
Net income after dividends on preference stock	—	—	—	148	—	148
Issuance of common stock	1	20	—	—	—	20
Capital contributions from parent company	—	—	7	—	—	7
Other comprehensive income (loss)	—	—	—	—	1	1
Cash dividends on common stock	—	—	—	(130)	—	(130)
Balance at December 31, 2015	**6**	**503**	**567**	**285**	**—**	**1,355**
Net income after dividends on preference stock	**—**	**—**	**—**	**131**	**—**	**131**
Capital contributions from parent company	**—**	**—**	**22**	**—**	**—**	**22**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**1**	**1**
Cash dividends on common stock	**—**	**—**	**—**	**(120)**	**—**	**(120)**
Balance at December 31, 2016	**6**	**$ 503**	**$ 589**	**$ 296**	**$ 1**	**$ 1,389**

The accompanying notes are an integral part of these financial statements.

NOTES TO FINANCIAL STATEMENTS
Gulf Power Company 2016 Annual Report

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Gulf Power Company (the Company) is a wholly-owned subsidiary of Southern Company, which is the parent company of the Company and three other traditional electric operating companies, as well as Southern Power, Southern Company Gas (as of July 1, 2016), SCS, Southern LINC, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure (as of May 9, 2016), Inc. (PowerSecure), and other direct and indirect subsidiaries. The traditional electric operating companies – the Company, Alabama Power, Georgia Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electric service to retail customers in northwest Florida and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern LINC provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and for other electric services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.

The equity method is used for entities in which the Company has significant influence but does not control.

The Company is subject to regulation by the FERC and the Florida PSC. As such, the Company's financial statements reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

Recently Issued Accounting Standards

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers,* replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

While the Company expects most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of such arrangements. The majority of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term. For such arrangements, the Company generally expects that the revenue from contracts with these customers will continue to be equivalent to the electricity supplied and billed in that period (including unbilled revenues) and the adoption of ASC 606 will not result in a significant shift in the timing of revenue recognition for such sales.

The Company's ongoing evaluation of other revenue streams and related contracts includes longer term contractual commitments and unregulated sales to customers. Some revenue arrangements, such as certain PPAs and alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on the Company's financial statements. In addition, the power and utilities industry is currently addressing other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). If final implementation guidance indicates CIAC will be accounted for under ASC 606 and offsetting regulatory treatment is not permitted, it could have a material impact on the Company's financial statements.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. The Company must select a transition method to be applied either retrospectively to each prior reporting period presented or retrospectively with a cumulative effect adjustment to retained earnings at the date of initial adoption. As the ultimate impact of the new standard has not yet been determined, the Company has not elected its transition method.

On February 25, 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged . ASU 2016-02 is

effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company is currently evaluating the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

On March 30, 2016, the FASB issued ASU No. 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5, 8, and 11 for disclosures impacted by ASU 2016-09.

On October 24, 2016, the FASB issued ASU No. 2016-16, *Income Taxes (Topic 740), Intra-Entity Transfers of Assets Other Than Inventory* (ASU 2016-16). Current GAAP prohibits the recognition of current and deferred income taxes for an affiliate asset transfer until the asset has been sold to an outside party. ASU 2016-16 requires an entity to recognize the income tax consequences of an affiliate transfer of an asset other than inventory when the transfer occurs. ASU 2016-16 is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. The amendments will be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The Company is currently assessing the impact of the standard on its financial statements and has not yet determined its ultimate impact.

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 $80 million , $81 million , and $80 million during 2016 , 2015 , and 2014 , respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has operating agreements with Georgia Power and Mississippi Power under which the Company owns a portion of Plant Scherer and Plant Daniel, respectively. Georgia Power operates Plant Scherer and Mississippi Power operates Plant Daniel. The Company reimbursed Georgia Power $8 million , $12 million , and $9 million and Mississippi Power $26 million , $27 million , and $31 million in 2016 , 2015 , and 2014 , respectively, for its proportionate share of related expenses. See Note 4 and Note 7 under "Operating Leases" for additional information.

The Company has an agreement with Alabama Power under which Alabama Power made transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA from a combined cycle plant located in Alabama. Payments by the Company to Alabama Power for the improvements were $12 million , $14 million , and $12 million in 2016 , 2015 , and 2014 , respectively, and are expected to be approximately $10 million annually for 2017 through 2023 , when the PPA expires. These costs have been approved for recovery by the Florida PSC through the Company's purchased power capacity cost recovery clause and by the FERC in the transmission facilities cost allocation tariff.

In 2016, the Company purchased a turbine rotor assembly from Southern Power for $6.8 million .

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2016 , 2015 , or 2014 .

The traditional electric operating companies, including the Company and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS, as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

NOTES (continued)
Gulf Power Company 2016 Annual Report

Regulatory Assets and Liabilities

The Company is subject to accounting requirements for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2016	2015	Note
	(in millions)		
Retiree benefit plans, net	**$ 160**	$ 147	(a,b)
PPA charges	**141**	163	(b,c)
Closure of ash ponds	**75**	29	(b,d)
Remaining book value of retired assets	**66**	4	(e)
Deferred income tax charges	**56**	59	(f)
Environmental remediation	**44**	46	(b,d)
Regulatory asset, offset to other cost of removal	**29**	29	(g)
Deferred return on transmission upgrades	**25**	10	(g)
Fuel-hedging assets, net	**24**	104	(b,h)
Other regulatory assets, net	**18**	16	(i)
Loss on reacquired debt	**18**	15	(j)
Asset retirement obligations, net	**7**	(1)	(b,f)
Other cost of removal obligations	**(278)**	(262)	(f)
Property damage reserve	**(40)**	(38)	(e)
Over recovered regulatory clause revenues	**(23)**	(22)	(k)
Deferred income tax credits	**(2)**	(3)	(f)
Total regulatory assets (liabilities), net	**$ 320**	$ 296	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Recovered and amortized over the average remaining service period which may range up to 14 years . See Note 2 for additional information.

(b) Not earning a return as offset in rate base by a corresponding asset or liability.

(c) Recovered over the life of the PPA for periods up to seven years .

(d) Recovered through the environmental cost recovery clause when the remediation or the work is performed.

(e) Recorded and recovered or amortized as approved by the Florida PSC.

(f) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years . Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(g) Recorded as authorized by the Florida PSC in a settlement agreement approved in December 2013 (2013 Rate Case Settlement Agreement). See Note 3 for additional information.

(h) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed five years . Upon final settlement, actual costs incurred are recovered through the fuel cost recovery clause.

(i) Comprised primarily of vacation pay. Other regulatory assets costs, with the exception of vacation pay, are recorded and recovered or amortized as approved by the Florida PSC. Vacation pay, including banked holiday pay, does not earn a return as offset in rate base by a corresponding liability; it is recorded as earned by employees and recovered as paid, generally within one year .

(j) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 40 years .

(k) Recorded and recovered or amortized as approved by the Florida PSC, generally within one year .

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. The Company continuously monitors the over or under recovered fuel cost balance in light of the inherent variability in fuel costs. The Company is required to notify the Florida PSC if the projected fuel cost over or under recovery is expected to exceed 10% of the projected fuel revenue applicable for the period and indicate if an adjustment to the fuel cost recovery factor is being requested. The Company has similar retail cost recovery clauses for energy conservation costs, purchased power capacity costs, and environmental compliance costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. Annually, the Company petitions for recovery of projected costs including any true-up amounts from prior periods, and approved rates are implemented each January. See Note 3 under "Retail Regulatory Matters" for additional information.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Federal ITCs utilized are deferred and amortized to income over the average life of the related property and state ITCs are recognized in the period in which the credit is claimed on the state income tax return. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

The Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction.

The Company's property, plant, and equipment in service consisted of the following at December 31:

	2016	2015
	(in millions)	
Generation	**$ 3,001**	$ 2,974
Transmission	**706**	691
Distribution	**1,241**	1,196
General	**191**	182
Plant acquisition adjustment	**1**	2
Total plant in service	**$ 5,140**	$ 5,045

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.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.5% in both 2016 and 2015 and 3.6% in 2014 . Depreciation studies are conducted periodically to update the composite rates. These studies are approved by the Florida PSC and the FERC. When property subject to depreciation is retired or

otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. As authorized by the Florida PSC in the 2013 Rate Case Settlement Agreement, the Company is allowed to reduce depreciation and record a regulatory asset in an aggregate amount up to $62.5 million between January 2014 and June 2017. See Note 3 herein under "Retail Regulatory Matters – Retail Base Rate Cases" for additional information.

Asset Retirement Obligations and Other Costs of Removal

AROs are computed as the present value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. The Company has received an order from the Florida PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for AROs primarily relates to facilities that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in April 2015 (CCR Rule), principally ash ponds, and to the closure of an ash pond at Plant Scholz. In addition, the Company has retirement obligations related to combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Florida PSC, and are reflected in the balance sheets.

Details of the AROs included in the balance sheets are as follows:

	2016	2015
	(in millions)	
Balance at beginning of year	**$ 130**	$ 17
Liabilities incurred	**1**	105
Liabilities settled	**(1)**	(1)
Accretion	**4**	2
Cash flow revisions	**2**	7
Balance at end of year	**$ 136**	$ 130

The increase in liabilities incurred in 2015 is primarily related to AROs associated with the portion of the Company's steam generation facilities impacted by the CCR Rule and the closure of an ash pond at Plant Scholz. In connection with permitting activity related to the coal ash pond at the retired Plant Scholz facility, the Company recorded additional AROs of $29 million in 2015.

The cost estimates for AROs related to CCR are based on information as of December 31, 2016 using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure for those facilities impacted by the CCR Rule. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing with respect to compliance activities, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the Company expects to continue to periodically update these estimates.

Allowance for Funds Used During Construction

The Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. The average annual AFUDC rate was 5.73% for all years presented. AFUDC, net of income taxes, as a percentage of net income after dividends on preference stock was 0.00% , 10.80% , and 10.93% for 2016 , 2015 , and 2014 , respectively.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Property Damage Reserve

The Company accrues for the cost of repairing damages from major storms and other uninsured property damages, including uninsured damages to transmission and distribution facilities, generation facilities, and other property. The costs of such damage are charged to the reserve. The Florida PSC approved annual accrual to the property damage reserve is $3.5 million , with a target level for the reserve between $48 million and $55 million . The Florida PSC also authorized the Company to make additional accruals above $3.5 million at the Company's discretion. The Company accrued total expenses of $3.5 million in each of 2016 , 2015 , and 2014 . As of December 31, 2016 and 2015 , the balance in the Company's property damage reserve totaled approximately $40 million and $38 million , respectively, which is included in deferred liabilities in the balance sheets.

When the property damage reserve is inadequate to cover the cost of major storms, the Florida PSC can authorize a storm cost recovery surcharge to be applied to customer bills. As authorized in the 2013 Rate Case Settlement Agreement, the Company may recover costs associated with any tropical systems named by the National Hurricane Center through the initiation of a storm surcharge. The storm surcharge will begin, on an interim basis, 60 days following the filing of a cost recovery petition. The storm surcharge generally may not exceed $4.00 / 1,000 KWHs on monthly residential bills in aggregate for a calendar year. This limitation does not apply if the Company incurs in excess of $100 million in storm recovery costs that qualify for recovery in a given calendar year. This threshold amount is inclusive of the amount necessary to replenish the storm reserve to the level that existed as of December 31, 2013. See Note 3 under "Retail Regulatory Matters – Retail Base Rate Cases" for additional details of the 2013 Rate Case Settlement Agreement.

Injuries and Damages Reserve

The Company is subject to claims and lawsuits arising in the ordinary course of business. As permitted by the Florida PSC, the Company accrues for the uninsured costs of injuries and damages by charges to income amounting to $1.6 million annually. The Florida PSC has also given the Company the flexibility to increase its annual accrual above $1.6 million to the extent the balance in the reserve does not exceed $2 million and to defer expense recognition of liabilities greater than the balance in the reserve. The cost of settling claims is charged to the reserve. The injuries and damages reserve had a balance of $1.4 million at December 31, 2016 , which is included in current liabilities in the balance sheets. The balance was zero at December 31, 2015 . There were no liabilities in excess of the reserve balance at December 31, 2016 . The Company recorded a liability with a corresponding regulatory asset of $1.7 million for estimated liabilities related to outstanding claims and suits in excess of the reserve balance at December 31, 2015 , of which $1.6 million and $0.1 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average cost of oil, natural gas, coal, transportation, and emissions allowances. Fuel is recorded to inventory when purchased and then expensed, at weighted average cost, as used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC. Emissions allowances granted by the EPA are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities on the balance sheets (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the Florida PSC approved fuel-hedging program result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of income. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. The Florida PSC approved a stipulation and agreement that prospectively imposed a moratorium on the Company's fuel-hedging program in October 2016 through December 31, 2017. The moratorium does not have an impact on the recovery of existing hedges entered into under the previously-approved hedging program. See Note 10 for additional information regarding derivatives.

Beginning in 2016, the Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2016 .

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). On December 19, 2016, the Company voluntarily contributed $48 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2017 . The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2017 , no other postretirement trust contributions are expected.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the net periodic costs for the pension and other postretirement benefit plans for the following year and the benefit obligations as of the measurement date are presented below.

Assumptions used to determine net periodic costs:	**2016**	2015	2014
Pension plans			
Discount rate – benefit obligations	**4.71%**	4.18%	5.02%
Discount rate – interest costs	**3.97**	4.18	5.02
Discount rate – service costs	**5.04**	4.48	5.02
Expected long-term return on plan assets	**8.20**	8.20	8.20
Annual salary increase	**4.46**	3.59	3.59
Other postretirement benefit plans			
Discount rate – benefit obligations	**4.51%**	4.04%	4.86%
Discount rate – interest costs	**3.68**	4.04	4.86
Discount rate – service costs	**4.88**	4.38	4.86
Expected long-term return on plan assets	**8.05**	8.07	8.08
Annual salary increase	**4.46**	3.59	3.59

Assumptions used to determine benefit obligations:	**2016**	2015
Pension plans		
Discount rate	**4.46%**	4.71%
Annual salary increase	**4.46**	4.46
Other postretirement benefit plans		
Discount rate	**4.25%**	4.51%
Annual salary increase	**4.46**	4.46

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2016 were as follows:

	Initial Cost Trend Rate	**Ultimate Cost Trend Rate**	**Year That Ultimate Rate is Reached**
Pre-65	6.50%	4.50%	2025
Post-65 medical	5.00	4.50	2025
Post-65 prescription	10.00	4.50	2025

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2016 as follows:

	1 Percent Increase	**1 Percent Decrease**
	(in millions)	
Benefit obligation	$ 4	$ 3
Service and interest costs	—	—

Pension Plans

The total accumulated benefit obligation for the pension plans was $460 million at December 31, 2016 and $424 million at December 31, 2015 . Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2016 and 2015 were as follows:

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 480**	$ 491
Service cost	**12**	12
Interest cost	**19**	20
Benefits paid	**(17)**	(20)
Actuarial (gain) loss	**23**	(23)
Balance at end of year	**517**	480
Change in plan assets		
Fair value of plan assets at beginning of year	**420**	435
Actual return (loss) on plan assets	**39**	4
Employer contributions	**49**	1
Benefits paid	**(17)**	(20)
Fair value of plan assets at end of year	**491**	420
Accrued liability	**$ (26)**	$ (60)

At December 31, 2016 , the projected benefit obligations for the qualified and non-qualified pension plans were $494 million and $23 million , respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2016 and 2015 related to the Company's pension plans consist of the following:

	2016	2015
	(in millions)	
Other regulatory assets, deferred	**$ 153**	$ 142
Other current liabilities	**(1)**	(1)
Employee benefit obligations	**(25)**	(59)

Presented below are the amounts included in regulatory assets at December 31, 2016 and 2015 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2017 .

	2016	2015	Estimated Amortization in 2017
		(in millions)	
Prior service cost	**$ 3**	$ 2	**$ 1**
Net (gain) loss	**150**	140	**7**
Regulatory assets	**$ 153**	$ 142	

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The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2016 and 2015 are presented in the following table:

	2016	2015
	(in millions)	
Regulatory assets:		
Beginning balance	**$ 142**	$ 146
Net (gain) loss	**16**	6
Change in prior service costs	**2**	—
Reclassification adjustments:		
Amortization of prior service costs	**(1)**	(1)
Amortization of net gain (loss)	**(6)**	(9)
Total reclassification adjustments	**(7)**	(10)
Total change	**11**	(4)
Ending balance	**$ 153**	$ 142

Components of net periodic pension cost were as follows:

	2016	2015	2014
		(in millions)	
Service cost	**$ 12**	$ 12	$ 10
Interest cost	**19**	20	19
Expected return on plan assets	**(34)**	(32)	(28)
Recognized net (gain) loss	**6**	9	5
Net amortization	**1**	1	1
Net periodic pension cost	**$ 4**	$ 10	$ 7

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2016 , estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2017	$ 20
2018	22
2019	23
2020	24
2021	26
2022 to 2026	149

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Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2016 and 2015 were as follows:

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 81**	$ 78
Service cost	**1**	1
Interest cost	**3**	3
Benefits paid	**(4)**	(4)
Actuarial (gain) loss	**2**	(1)
Plan amendment	**—**	4
Balance at end of year	**83**	81
Change in plan assets		
Fair value of plan assets at beginning of year	**17**	18
Actual return (loss) on plan assets	**2**	—
Employer contributions	**3**	3
Benefits paid	**(4)**	(4)
Fair value of plan assets at end of year	**18**	17
Accrued liability	**$ (65)**	$ (64)

Amounts recognized in the balance sheets at December 31, 2016 and 2015 related to the Company's other postretirement benefit plans consist of the following:

	2016	2015
	(in millions)	
Other regulatory assets, deferred	**$ 11**	$ 10
Other current liabilities	**(1)**	(1)
Other regulatory liabilities, deferred	**(4)**	(5)
Employee benefit obligations	**(64)**	(63)

Approximately $7 million and $5 million was included in net regulatory assets at December 31, 2016 and 2015 , respectively, related to the net loss for the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost. The estimated amortization of such amounts for 2017 is immaterial.

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2016 and 2015 are presented in the following table:

	2016	2015
	(in millions)	
Net regulatory assets (liabilities):		
Beginning balance	**$ 5**	$ 2
Net (gain) loss	**2**	1
Change in prior service costs	**—**	2
Total change	**2**	3
Ending balance	**$ 7**	$ 5

Components of the other postretirement benefit plans' net periodic cost were as follows:

	2016	2015	2014
		(in millions)	
Service cost	**$ 1**	$ 1	$ 1
Interest cost	**3**	3	3
Expected return on plan assets	**(1)**	(1)	(1)
Net periodic postretirement benefit cost	**$ 3**	$ 3	$ 3

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	**Subsidy Receipts**	**Total**
		(in millions)	
2017	$ 5	$ —	$ 5
2018	5	—	5
2019	6	(1)	5
2020	6	(1)	5
2021	6	(1)	5
2022 to 2026	30	(3)	27

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.

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The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2016 and 2015 , along with the targeted mix of assets for each plan, is presented below:

	Target	**2016**	2015
Pension plan assets:			
Domestic equity	26%	**29%**	30%
International equity	25	**22**	23
Fixed income	23	**29**	23
Special situations	3	**2**	2
Real estate investments	14	**13**	16
Private equity	9	**5**	6
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	25%	**28%**	29%
International equity	24	**21**	22
Domestic fixed income	25	**31**	25
Special situations	3	**2**	2
Real estate investments	14	**13**	16
Private equity	9	**5**	6
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2016 and 2015 . The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management

relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- ***Domestic and international equity.*** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- ***Fixed income.*** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- ***Real estate investments, private equity, and special situations investments.*** Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

The fair values of pension plan assets as of December 31, 2016 and 2015 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. For 2015, investments in special situations were presented in the table below based on the nature of the investment.

	Fair Value Measurements Using				
As of December 31, 2016:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Assets:					
Domestic equity (*)	$ 93	$ 43	$ —	$ —	$ 136
International equity (*)	57	52	—	—	109
Fixed income:					
U.S. Treasury, government, and agency bonds	—	27	—	—	27
Mortgage- and asset-backed securities	—	1	—	—	1
Corporate bonds	—	47	—	—	47
Pooled funds	—	24	—	—	24
Cash equivalents and other	46	—	—	—	46
Real estate investments	14	—	—	53	67
Special situations	—	—	—	8	8
Private equity	—	—	—	25	25
Total	$ 210	$ 194	$ —	$ 86	$ 490

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

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As of December 31, 2015:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Assets:					
Domestic equity (*)	$ 73	$ 31	$ —	$ —	$ 104
International equity (*)	54	45	—	—	99
Fixed income:					
U.S. Treasury, government, and agency bonds	—	21	—	—	21
Mortgage- and asset-backed securities	—	9	—	—	9
Corporate bonds	—	51	—	—	51
Pooled funds	—	23	—	—	23
Cash equivalents and other	—	7	—	—	7
Real estate investments	14	—	—	55	69
Private equity	—	—	—	29	29
Total	$ 141	$ 187	$ —	$ 84	$ 412

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

The fair values of other postretirement benefit plan assets as of December 31, 2016 and 2015 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

As of December 31, 2016:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Assets:					
Domestic equity (*)	$ 3	$ 2	$ —	$ —	$ 5
International equity (*)	2	2	—	—	4
Fixed income:					
U.S. Treasury, government, and agency bonds	—	1	—	—	1
Corporate bonds	—	2	—	—	2
Pooled funds	—	1	—	—	1
Cash equivalents and other	2	—	—	—	2
Real estate investments	1	—	—	2	3
Private equity	—	—	—	1	1
Total	$ 8	$ 8	$ —	$ 3	$ 19

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

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	Fair Value Measurements Using				
As of December 31, 2015:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Assets:					
Domestic equity (*)	$ 3	$ 1	$ —	$ —	$ 4
International equity (*)	2	2	—	—	4
Fixed income:					
U.S. Treasury, government, and agency bonds	—	1	—	—	1
Corporate bonds	—	2	—	—	2
Pooled funds	—	1	—	—	1
Cash equivalents and other	1	—	—	—	1
Real estate investments	1	—	—	2	3
Private equity	—	—	—	1	1
Total	$ 7	$ 7	$ —	$ 3	$ 17

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2016 , 2015 , and 2014 were $5 million , $4 million , and $4 million , respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up affected sites. The Company received authority from the Florida PSC to recover approved environmental compliance costs through the environmental cost recovery clause. The Florida PSC reviews costs and adjusts rates up or down annually.

The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable. At December 31, 2016 , the Company's environmental remediation liability included estimated costs of environmental remediation projects of approximately $44 million , of which approximately $4 million is included in under recovered regulatory clause revenues and other current liabilities and approximately $40 million is included in other regulatory assets, deferred and other deferred credits and

liabilities. These estimated costs primarily relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at the Company's substations. The schedule for completion of the remediation projects is subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through the Company's environmental cost recovery clause; therefore, these liabilities have no impact on net income.

The ultimate outcome of these matters cannot be determined at this time; however, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, the Company does not believe that additional liabilities, if any, at these sites would be material to the Company's financial statements.

FERC Matters

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric operating companies' (including the Company's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies (including the Company) and Southern Power filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.

On December 9, 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. The traditional electric operating companies (including the Company) and Southern Power expect to make a compliance filing within 30 days accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

The ultimate outcome of these matters cannot be determined at this time.

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates.

Retail Base Rate Cases

In 2013, the Florida PSC approved the 2013 Rate Case Settlement Agreement among the Company and all of the intervenors to the Company's retail base rate case. Under the terms of the 2013 Rate Case Settlement Agreement, the Company (1) increased base rates approximately $35 million and $20 million annually effective January 2014 and 2015, respectively; (2) continued its authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); and (3) accrued a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 through January 1, 2017.

The 2013 Rate Case Settlement Agreement also provides that the Company may reduce depreciation and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million from January 2014 through June 2017. In any given month, such depreciation reduction may not exceed the amount necessary for the retail ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized retail ROE range then in effect. Recovery of the regulatory asset will occur over a period to be determined by the Florida PSC in the 2016 Rate Case, as defined below. For 2014 and 2015, the Company recognized reductions in depreciation expense of $8.4 million and $20.1 million , respectively. No net reduction in depreciation was recorded in 2016.

On October 12, 2016, the Company filed a petition (2016 Rate Case) with the Florida PSC requesting an annual increase in retail rates and charges of $106.8 million based on the projected test year of January 1, 2017 through December 31, 2017 and a retail ROE of

11% compared to the current retail ROE of 10.25% . The requested increase includes recovery of the portion of Plant Scherer Unit 3 that has been rededicated to serving retail customers following the contract expirations at the end of 2015 and May 2016. If retail recovery of Plant Scherer Unit 3 is not approved by the Florida PSC in the 2016 Rate Case, the Company may consider an asset sale. The current book value of the Company's ownership of Plant Scherer Unit 3 could exceed market value which could result in a material loss. The Florida PSC is expected to make a decision on the 2016 Rate Case in the second quarter 2017. The Company has requested that the increase in base rates, if approved by the Florida PSC, become effective in July 2017. The ultimate outcome of this matter cannot be determined at this time.

Cost Recovery Clauses

On November 2, 2016, the Florida PSC approved the Company's 2017 annual cost recovery clause rates for its fuel, purchased power capacity, environmental, and energy conservation cost recovery clauses. The net effect of the approved changes is a decrease of approximately $41 million in annual revenues effective in January 2017. In general, the decreased revenues will not have a significant impact on net income since most of the revenues will be offset by lower expenses. However, certain costs associated with the ongoing ownership and operation of Plant Scherer Unit 3 were included in the environmental cost recovery clause rate, which increased annual revenues by approximately $12 million in 2016 and is expected to increase revenues by an incremental $2 million for a total of approximately $14 million in 2017. The final disposition of these costs, and the related impact on rates, is subject to the Florida PSC's ultimate ruling on whether costs associated with Plant Scherer Unit 3 are recoverable from retail customers, which is expected to be decided in the 2016 Rate Case as discussed previously. The ultimate outcome of this matter cannot be determined at this time.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment.

Retail Fuel Cost Recovery

The Company has established fuel cost recovery rates as approved by the Florida PSC. If, at any time during the year, the projected year-end fuel cost over or under recovery balance exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested.

At December 31, 2016 and 2015 , the over recovered fuel balance was approximately $15 million and $18 million , respectively, which is included in other regulatory liabilities, current in the balance sheets.

Purchased Power Capacity Recovery

The Company has established purchased power capacity recovery cost rates as approved by the Florida PSC. If the projected year-end purchased power capacity cost over or under recovery balance exceeds 10% of the projected purchased power capacity revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the purchased power capacity cost recovery factor is being requested.

At December 31, 2016 and 2015 , the under recovered purchased power capacity balance was immaterial.

Environmental Cost Recovery

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operations and maintenance expenses, emissions allowance expense, depreciation, and a return on net average investment. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the FDEP for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA.

Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2016 , the over recovered environmental balance of approximately $8 million , along with the current portion of projected environmental expenditures, was included in under recovered regulatory clause revenues in the balance sheet. At December 31, 2015 , the over recovered environmental balance was immaterial.

In 2012, the Mississippi PSC approved Mississippi Power's request for a certificate of public convenience and necessity to construct scrubbers on Plant Daniel Units 1 and 2, which were placed in service in November 2015. These units are jointly owned by Mississippi Power and the Company, with 50% ownership each. The total cost of the project was approximately $653 million , with the Company's portion being approximately $316 million , excluding AFUDC. The Company's portion of the cost is being recovered through the environmental cost recovery clause.

Energy Conservation Cost Recovery

Every five years , the Florida PSC establishes new numeric conservation goals covering a 10 -year period for utilities to reduce annual energy and seasonal peak demand using demand-side management (DSM) programs. After the goals are established, utilities develop plans and programs to meet the approved goals. The costs for these programs are recovered through rates established annually in the energy conservation cost recovery (ECCR) clause.

At December 31, 2016 , the under recovered ECCR balance was approximately $4 million , which is included in under recovered regulatory clause revenues in the balance sheet. At December 31, 2015 , the over recovered ECCR balance was approximately $4 million , which is included in other regulatory liabilities, current in the balance sheet.

Other Matters

As a result of the cost to comply with environmental regulations imposed by the EPA, the Company retired its coal-fired generation at Plant Smith Units 1 and 2 (357 MWs) on March 31, 2016. The Company filed a petition with the Florida PSC requesting permission to recover the remaining net book value of Plant Smith Units 1 and 2 and the remaining materials and supplies associated with these units as of the retirement date. On August 29, 2016, the Florida PSC approved the Company's request to reclassify these costs, totaling $63 million , to a regulatory asset for recovery over a period to be decided in the 2016 Rate Case. The ultimate outcome of this matter cannot be determined at this time.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Mississippi Power jointly own Plant Daniel Units 1 and 2, which together represent capacity of 1,000 MWs. Plant Daniel is a generating plant located in Jackson County, Mississippi. In accordance with the operating agreement, Mississippi Power acts as the Company's agent with respect to the construction, operation, and maintenance of these units.

The Company and Georgia Power jointly own the 818 -MW capacity Plant Scherer Unit 3. Plant Scherer is a generating plant located near Forsyth, Georgia. In accordance with the operating agreement, Georgia Power acts as the Company's agent with respect to the construction, operation, and maintenance of the unit.

At December 31, 2016 , the Company's percentage ownership and investment in these jointly-owned facilities were as follows:

	Plant Scherer Unit 3 (coal)	Plant Daniel Units 1 & 2 (coal)
	(in millions)	
Plant in service	$ 398	$ 680
Accumulated depreciation	143	202
Construction work in progress	7	7
Company ownership	25%	50%

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income and the Company is responsible for providing its own financing.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and various combined and separate state income tax returns. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

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Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2016	2015	2014
		(in millions)	
Federal -			
Current	$ 34	$ (3)	$ 23
Deferred	45	80	52
	79	77	75
State -			
Current	—	5	—
Deferred	12	10	13
	12	15	13
Total	$ 91	$ 92	$ 88

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2016	2015
	(in millions)	
Deferred tax liabilities-		
Accelerated depreciation	$ 834	$ 812
Property basis differences	123	133
Pension and other employee benefits	58	39
Regulatory assets	45	16
Regulatory assets associated with employee benefit obligations	65	59
Regulatory assets associated with asset retirement obligations	55	40
Other	12	10
Total	1,192	1,109
Deferred tax assets-		
Federal effect of state deferred taxes	37	33
Postretirement benefits	26	26
Pension and other employee benefits	72	65
Property reserve	17	15
Asset retirement obligations	55	40
Alternative minimum tax carryforward	18	18
Other	19	19
Total	244	216
Accumulated deferred income taxes	$ 948	$ 893

The application of bonus depreciation provisions in current tax law significantly increased deferred tax liabilities related to accelerated depreciation in 2016 and 2015.

At December 31, 2016 , tax-related regulatory assets to be recovered from customers were $58 million . These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest.

At December 31, 2016 , the tax-related regulatory liabilities to be credited to customers were $2 million . These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and unamortized ITCs.

In accordance with regulatory requirements, deferred federal ITCs are amortized over the average life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner are not material for the periods presented. At December 31, 2016 , all ITCs available to reduce federal income taxes payable had been utilized.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2016	2015	2014
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**3.4**	3.9	3.5
Non-deductible book depreciation	**0.6**	0.5	0.4
Differences in prior years' deferred and current tax rates	**(0.1)**	(0.1)	(0.1)
AFUDC equity	**—**	(1.8)	(1.8)
Other, net	**0.6**	(0.6)	0.1
Effective income tax rate	**39.5%**	36.9%	37.1%

The increase in the Company's 2016 effective tax rate is primarily the result of the decrease in nontaxable AFUDC equity.

On March 30, 2016, the FASB issued ASU 2016-09, which changes the accounting for income taxes for share-based payment award transactions. Entities are required to recognize all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation as income tax expense or benefit in the income statement. The adoption of ASU 2016-09 did not have a material impact on the Company's overall effective tax rate. See Note 1 under "Recently Issued Accounting Standards" for additional information.

Unrecognized Tax Benefits

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, but an estimate of the range of reasonably possible outcomes cannot be determined at this time.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013, 2014, and 2015 federal income tax returns and has received partial acceptance letters from the IRS; however, the IRS has not finalized its audits. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

6. FINANCING

Securities Due Within One Year

At December 31, 2016 and 2015, the Company had $87 million and $110 million of long-term debt due within one year , respectively.

Maturities through 2021 applicable to total long-term debt include $87 million in 2017 and $175 million in 2020. There are no scheduled maturities in 2018, 2019, or 2021.

Bank Term Loans

In May 2016, the Company entered into an 11 -month floating rate bank loan bearing interest based on one-month LIBOR. This short-term loan was for $100 million aggregate principal amount and the proceeds were used to repay existing indebtedness and for working capital and other general corporate purposes.

This bank loan has a covenant that limits debt levels to 65% of total capitalization, as defined in the agreement. For purposes of this definition, debt excludes certain hybrid securities. At December 31, 2016 , the Company was in compliance with its debt limit.

Senior Notes

At December 31, 2016 and 2015 , the Company had a total of $777 million and $1.01 billion of senior notes outstanding, respectively. These senior notes are effectively subordinate to all secured debt of the Company, which totaled approximately $41 million at both December 31, 2016 and 2015 .

In May 2016, the Company redeemed $125 million aggregate principal amount of its Series 2011A 5.75% Senior Notes due June 1, 2051.

Pollution Control Revenue Bonds

Pollution control revenue bond obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bond obligations outstanding at December 31, 2016 and 2015 was $309 million .

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. No shares of preferred stock or Class A preferred stock were outstanding at December 31, 2016 . The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. Certain series of the preference stock are subject to redemption at the option of the Company on or after a specified date (typically five or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the preference stock. In addition, certain series of the preference stock may be redeemed earlier at a redemption price equal to 100% of the liquidation amount plus a make-whole premium based on the present value of the liquidation amount and future dividends.

In January 2015, the Company issued 200,000 shares of common stock to Southern Company and realized proceeds of $20 million . The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

Subsequent to December 31, 2016, the Company issued 1,750,000 shares of common stock to Southern Company and realized proceeds of $175 million . The proceeds were used for general corporate purposes, including the Company's continuous construction program.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Assets Subject to Lien

The Company has granted a lien on its property at Plant Daniel in connection with the issuance of two series of pollution control revenue bonds with an aggregate outstanding principal amount of $41 million as of December 31, 2016 . There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its subsidiaries.

Bank Credit Arrangements

At December 31, 2016 , committed credit arrangements with banks were as follows:

Expires				Executable Term Loans		Expires Within One Year	
2017	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)		(in millions)		(in millions)		(in millions)	
$ 85	$ 195	$ 280	$ 280	$ 45	$ —	$ 25	$ 60

Most of the bank credit arrangements require payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than $^1/_4$ of 1% for the Company.

Subject to applicable market conditions, the Company expects to renew or replace its bank credit arrangements as needed, prior to expiration. In connection therewith, the Company may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

Most of these bank credit arrangements contain covenants that limit the Company's debt level to 65% of total capitalization, as defined in the arrangements. For purposes of these definitions, debt excludes certain hybrid securities. At December 31, 2016 , the Company was in compliance with these covenants.

Most of the $280 million of unused credit arrangements with banks provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2016 was approximately $82 million . In addition, at December 31, 2016 , the Company had $86 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months .

For short-term cash needs, the Company borrows primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements described above. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank loans are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period	
	Amount Outstanding	**Weighted Average Interest Rate**
	(in millions)	
December 31, 2016:		
Commercial paper	**$ 168**	**1.1%**
Short-term bank debt	**100**	**1.5%**
Total	**$ 268**	**1.2%**
December 31, 2015:		
Commercial paper	$ 142	0.7%

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil fuel which are not recognized on the balance sheets. In 2016 , 2015 , and 2014 , the Company incurred fuel expense of $432 million , $445 million , and $605 million , respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

In addition, the Company has entered into various long-term commitments for the purchase of capacity, energy, and transmission, some of which are accounted for as operating leases. The energy-related costs associated with PPAs are recovered through the fuel cost recovery clause. The capacity and transmission-related costs associated with PPAs are recovered through the purchased power capacity cost recovery clause. Capacity expense under a PPA accounted for as an operating lease was $75 million for both 2016 and 2015 and $50 million for 2014 .

Estimated total minimum long-term commitments at December 31, 2016 were as follows:

	Operating Lease PPA
	(in millions)
2017	$ 79
2018	79
2019	79
2020	79
2021	79
2022 and thereafter	112
Total	$ 507

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional electric operating companies and Southern Power. Under these agreements, each of the traditional electric operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional electric operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

In addition to the operating lease PPA discussed above, the Company has other operating lease agreements with various terms and expiration dates. Total rent expense was $9 million , $14 million , and $15 million for 2016 , 2015 , and 2014 , respectively.

Estimated total minimum lease payments under these operating leases at December 31, 2016 were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
		(in millions)	
2017	$ 7	$ 1	$ 8
2018	5	1	6
2019	—	1	1
2020	—	—	—
2021	—	—	—
2022 and thereafter	—	1	1
Total	$ 12	$ 4	$ 16

The Company and Mississippi Power jointly entered into an operating lease agreement for aluminum railcars for the transportation of coal to Plant Daniel. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value or to renew the leases at the end of the lease term. The Company and Mississippi Power also have separate lease agreements for other railcars that do not include purchase options. The Company's 50% share of the lease costs, charged to fuel inventory and recovered through the retail fuel cost recovery clause, was $2 million in both 2016 and 2015 and $3 million in 2014 . The Company's total annual railcar lease payments for 2017 are $2 million and are immaterial for 2018 through 2020.

In addition to railcar leases, the Company has operating lease agreements for barges and towboats for the transport of coal to Plant Crist. The Company has the option to renew the leases at the end of the lease term. The Company's lease costs, charged to fuel inventory and recovered through the retail fuel cost recovery clause, were $5 million in 2016 and $10 million in both 2015 and 2014. The Company's annual barge and towboat payments for 2017 and 2018 are expected to be approximately $5 million each year.

8. STOCK COMPENSATION

Stock-Based Compensation

Stock-based compensation primarily in the form of Southern Company performance share units may be granted through the Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2016 , there were 184 current and former employees participating in the stock option and performance share unit programs.

Stock Options

Through 2009, stock-based compensation granted to employees consisted exclusively of non-qualified stock options. The exercise price for stock options granted equaled the stock price of Southern Company common stock on the date of grant. Stock options vest on a pro rata basis over a maximum period of three years from the date of grant or immediately upon the retirement or death of the employee. Options expire no later than 10 years after the grant date. All unvested stock options vest immediately upon a change in control where Southern Company is not the surviving corporation. Compensation expense is generally recognized on a straight-line basis over the three -year vesting period with the exception of employees that are retirement eligible at the grant date and employees that will become retirement eligible during the vesting period. Compensation expense in those instances is recognized at the grant date for employees that are retirement eligible and through the date of retirement eligibility for those employees that become retirement eligible during the vesting period. In 2015, Southern Company discontinued the granting of stock options.

The weighted average grant-date fair value of stock options granted during 2014 derived using the Black-Scholes stock option pricing model was $2.20 .

The compensation cost related to the grant of Southern Company stock options to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. Compensation cost and related tax benefits recognized in the Company's financial statements were not material for any year presented. As of December 31, 2016 , the amount of unrecognized compensation cost related to stock option awards not yet vested was immaterial.

The total intrinsic value of options exercised during the years ended December 31, 2016 , 2015, and 2014 was $3 million , $2 million , and $5 million , respectively. No cash proceeds are received by the Company upon the exercise of stock options. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1 million for the years ended December 31, 2016 and 2015 and $2 million for 2014. Prior to the adoption of ASU 2016-09, the excess tax benefits related to the exercise of stock options were recognized in the Company's financial statements with a credit to equity. Upon the adoption of ASU 2016-09, beginning in 2016, all tax benefits related to the exercise of stock options are recognized in income. As of December 31, 2016 , the aggregate intrinsic value for the options outstanding and options exercisable was $6 million and $5 million , respectively.

Performance Share Units

From 2010 through 2014, stock-based compensation granted to employees included performance share units in addition to stock options. Beginning in 2015, stock-based compensation consisted exclusively of performance share units. Performance share units granted to employees vest at the end of a three -year performance period. All unvested performance share units vest immediately upon a change in control where Southern Company is not the surviving corporation. Shares of Southern Company common stock are delivered to employees at the end of the performance period with the number of shares issued ranging from 0% to 200% of the target number of performance share units granted, based on achievement of the performance goals established by the Compensation Committee of the Southern Company Board of Directors.

The performance goal for all performance share units issued from 2010 through 2014 was based on the total shareholder return (TSR) for Southern Company common stock during the three -year performance period as compared to a group of industry peers. For these performance share units, at the end of three years , active employees receive shares based on Southern Company's performance while retired employees receive a pro rata number of shares based on the actual months of service during the performance period prior to retirement. The fair value of TSR-based performance share unit awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's common stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three -year performance period without remeasurement.

Beginning in 2015, Southern Company issued two additional types of performance share units to employees in addition to the TSR-based awards. These included performance share units with performance goals based on cumulative earnings per share

(EPS) over the performance period and performance share units with performance goals based on Southern Company's equity-weighted ROE over the performance period. The EPS-based and ROE-based awards each represent 25% of total target grant date fair value of the performance share unit awards granted. The remaining 50% of the target grant date fair value consists of TSR-based awards. In contrast to the Monte Carlo simulation model used to determine the fair value of the TSR-based awards, the fair values of the EPS-based awards and the ROE-based awards are based on the closing stock price of Southern Company common stock on the date of the grant. Compensation expense for the EPS-based and ROE-based awards is generally recognized ratably over the three -year performance period initially assuming a 100% payout at the end of the performance period. The TSR-based performance share units, along with the EPS-based and ROE-based awards, vest immediately upon the retirement of the employee. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately while compensation expense for employees that become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility. The expected payout related to the EPS-based and ROE-based awards is reevaluated annually with expense recognized to date increased or decreased based on the number of shares currently expected to be issued. Unlike the TSR-based awards, the compensation expense ultimately recognized for the EPS-based awards and the ROE-based awards will be based on the actual number of shares issued at the end of the performance period.

For the years ended December 31, 2016 , 2015 , and 2014 , employees of the Company were granted performance share units of 57,333 , 48,962 , and 37,829 , respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2016 , 2015 , and 2014 , determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $45.18 , $46.38 , and $37.54 , respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2016 and 2015 was $48.83 and $47.75 , respectively.

For the years ended December 31, 2016 , 2015 , and 2014 , total compensation cost for performance share units recognized in income was $3 million , $2 million , and $1 million , respectively. The related tax benefit also recognized in income was $1 million in 2016 and 2015 and immaterial in 2014. The compensation cost related to the grant of Southern Company performance share units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2016 , $2 million of total unrecognized compensation cost related to performance share award units will be recognized over a weighted-average period of approximately 22 months .

9. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2016 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

	Fair Value Measurements Using			
As of December 31, 2016:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Cash equivalents	$ 20	$ —	$ —	$ 20
Energy-related derivatives	—	5	—	5
Total	$ 20	$ 5	$ —	$ 25
Liabilities:				
Energy-related derivatives	$ —	$ 29	$ —	$ 29

As of December 31, 2015 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

	Fair Value Measurements Using			
As of December 31, 2015:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Interest rate derivatives	$ —	$ 1	$ —	$ 1
Cash equivalents	18	—	—	18
Total	$ 18	$ 1	$ —	$ 19
Liabilities:				
Energy-related derivatives	$ —	$ 100	$ —	$ 100

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflect the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and occasionally, implied volatility of interest rate options. The interest rate derivatives are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 10 for additional information on how these derivatives are used.

As of December 31, 2016 and 2015 , other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2016	**$ 1,074**	**$ 1,097**
2015	$ 1,303	$ 1,339

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates available to the Company.

10. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net basis. See Note 9 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in energy-related commodity prices. The Company manages fuel-hedging programs, implemented per the guidelines of the Florida PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. The Florida PSC approved a stipulation and agreement that prospectively imposed a moratorium on the Company's fuel-hedging program in October 2016 through December 31, 2017. The moratorium does not have an impact on the recovery of existing hedges entered into under the previously-approved hedging program.

Energy-related derivative contracts are accounted for under one of three methods:

- *Regulatory Hedges* — Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery clause.
- *Cash Flow Hedges* — Gains and losses on energy-related derivatives designated as cash flow hedges (which are mainly used to hedge anticipated purchases and sales) are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* — Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2016 , the net volume of energy-related derivative contracts for natural gas positions totaled 51 million mmBtu for the Company, with the longest hedge date of 2020 over which it is hedging its exposure to the variability in future cash flows for forecasted transactions.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the

derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings.

At December 31, 2016 , the following interest rate derivative was outstanding:

	Notional Amount	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2016
	(in millions)				*(in millions)*
Cash Flow Hedges of Forecasted Debt					
	$ 80	3-month LIBOR	2.32%	December 2026	$ —

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2017 are immaterial. The Company has deferred gains and losses that are expected to be amortized into earnings through 2026 .

Derivative Financial Statement Presentation and Amounts

The Company enters into energy-related and interest rate derivative contracts that may contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. At December 31, 2016 , fair value amounts of derivative assets and liabilities on the balance sheets are presented net to the extent that there are netting arrangements or similar agreements with the counterparties. At December 31, 2015 , the fair value amounts of derivative instruments were presented gross on the balance sheets.

At December 31, 2016 and 2015 , the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	2016		2015	
Derivative Category and Balance Sheet Location	**Assets**	**Liabilities**	Assets	Liabilities
		(in millions)		
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Liabilities from risk management activities	**$ 4**	**$ 12**	$ —	$ 49
Other deferred charges and assets/Other deferred credits and liabilities	**1**	**17**	—	51
Total derivatives designated as hedging instruments for regulatory purposes	**$ 5**	**$ 29**	$ —	$ 100
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Interest rate derivatives:				
Other current assets/Liabilities from risk management activities	**—**	**—**	1	—
Gross amounts recognized	**$ 5**	**$ 29**	$ 1	$ 100
Gross amounts offset	**$ (4)**	**$ (4)**	$ —	$ —
Net amounts recognized in the Balance Sheets (*)	**$ 1**	**$ 25**	$ 1	$ 100

(*) At December 31, 2015 , the fair value amounts for derivative contracts subject to netting arrangements were presented gross on the balance sheet.

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2016 and 2015 .

At December 31, 2016 and 2015 , the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivatives designated as regulatory hedging instruments and deferred were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2016**	2015	**Balance Sheet Location**	**2016**	2015
		(in millions)			*(in millions)*	
Energy-related derivatives: (*)	Other regulatory assets, current	**$ (9)**	$ (49)	Other regulatory liabilities, current	**$ 1**	$ —
	Other regulatory assets, deferred	**(16)**	(51)	Other regulatory liabilities, deferred	**—**	—
Total energy-related derivative gains (losses)		**$ (25)**	$ (100)		**$ 1**	$ —

(*) At December 31, 2016 , the unrealized gains and losses for derivative contracts subject to netting arrangements were presented net on the balance sheet. At December 31, 2015 , the unrealized gains and losses for derivative contracts were presented gross on the balance sheet.

For the years ended December 31, 2016 , 2015 , and 2014 , the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Recognized in OCI on Derivative (Effective Portion)**			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**			
					Amount		
Derivative Category	**2016**	2015	2014	**Statements of Income Location**	**2016**	2015	2014
		(in millions)				*(in millions)*	
Interest rate derivatives	**$ —**	$ 1	$ —	Interest expense, net of amounts capitalized	**$ (1)**	$ (1)	$ (1)

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2016 , 2015 , and 2014 , the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income were not material.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2016 , the Company's collateral posted with its derivative counterparties was not material.

At December 31, 2016 , the fair value of derivative liabilities with contingent features, including certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade because of joint and several liability features underlying these derivatives, was immaterial.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2016 and 2015 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preference Stock
		(in millions)	
March 2016	**$ 335**	**$ 65**	**$ 29**
June 2016	**365**	**74**	**34**
September 2016	**436**	**90**	**45**
December 2016	**349**	**54**	**23**
March 2015	$ 357	$ 72	$ 37
June 2015	384	69	35
September 2015	429	91	48
December 2015	313	58	28

In accordance with the adoption of ASU 2016-09 (see Note 1 under "Recently Issued Accounting Standards"), previously reported amounts for income tax expense were reduced by an immaterial amount for the first, second, and third quarters of 2016.

The Company's business is influenced by seasonal weather conditions.

SELECTED FINANCIAL AND OPERATING DATA 2012 - 2016
Gulf Power Company 2016 Annual Report

	2016	2015	2014	2013	2012
Operating Revenues (in millions)	**$ 1,485**	$ 1,483	$ 1,590	$ 1,440	$ 1,440
Net Income After Dividends on Preference Stock (in millions)	**$ 131**	$ 148	$ 140	$ 124	$ 126
Cash Dividends on Common Stock (in millions)	**$ 120**	$ 130	$ 123	$ 115	$ 116
Return on Average Common Equity (percent)	**9.52**	11.11	11.02	10.30	10.92
Total Assets (in millions) [(a)(b)]	**$ 4,822**	$ 4,920	$ 4,697	$ 4,321	$ 4,167
Gross Property Additions (in millions)	**$ 179**	$ 247	$ 361	$ 305	$ 325
Capitalization (in millions):					
Common stock equity	**$ 1,389**	$ 1,355	$ 1,309	$ 1,235	$ 1,181
Preference stock	**147**	147	147	147	98
Long-term debt [(a)]	**987**	1,193	1,362	1,150	1,178
Total (excluding amounts due within one year)	**$ 2,523**	$ 2,695	$ 2,818	$ 2,532	$ 2,457
Capitalization Ratios (percent):					
Common stock equity	**55.1**	50.3	46.5	48.8	48.1
Preference stock	**5.8**	5.4	5.2	5.8	4.0
Long-term debt [(a)]	**39.1**	44.3	48.3	45.4	47.9
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**398,501**	393,149	388,292	383,980	379,922
Commercial	**56,091**	55,460	54,892	54,567	53,808
Industrial	**254**	248	260	260	264
Other	**569**	614	603	582	577
Total	**455,415**	449,471	444,047	439,389	434,571
Employees (year-end)	**1,352**	1,391	1,384	1,410	1,416

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $8 million, $8 million, and $8 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(b) A reclassification of deferred tax assets from Total Assets of $3 million, $8 million, and $2 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

SELECTED FINANCIAL AND OPERATING DATA 2012 - 2016 (continued)
Gulf Power Company 2016 Annual Report

	2016	2015	2014	2013	2012
Operating Revenues (in millions):					
Residential	$ 714	$ 698	$ 700	$ 632	$ 609
Commercial	410	403	408	395	390
Industrial	152	144	153	139	140
Other	5	4	6	4	5
Total retail	1,281	1,249	1,267	1,170	1,144
Wholesale — non-affiliates	61	107	129	109	107
Wholesale — affiliates	75	58	130	100	124
Total revenues from sales of electricity	1,417	1,414	1,526	1,379	1,375
Other revenues	68	69	64	61	65
Total	$ 1,485	$ 1,483	$ 1,590	$ 1,440	$ 1,440
Kilowatt-Hour Sales (in millions):					
Residential	5,358	5,365	5,362	5,089	5,054
Commercial	3,869	3,898	3,838	3,810	3,859
Industrial	1,830	1,798	1,849	1,700	1,725
Other	25	25	26	21	25
Total retail	11,082	11,086	11,075	10,620	10,663
Wholesale — non-affiliates	751	1,040	1,670	1,163	977
Wholesale — affiliates	2,784	1,906	3,284	3,127	4,370
Total	14,617	14,032	16,029	14,910	16,010
Average Revenue Per Kilowatt-Hour (cents):					
Residential	13.33	13.01	13.06	12.43	12.06
Commercial	10.60	10.34	10.64	10.37	10.11
Industrial	8.31	8.01	8.28	8.15	8.14
Total retail	11.56	11.27	11.44	11.02	10.73
Wholesale	3.85	5.60	5.23	4.87	4.31
Total sales	9.69	10.08	9.52	9.25	8.59
Residential Average Annual					
Kilowatt-Hour Use Per Customer	13,515	13,705	13,865	13,301	13,303
Residential Average Annual					
Revenue Per Customer	$ 1,801	$ 1,783	$ 1,811	$ 1,653	$ 1,604
Plant Nameplate Capacity					
Ratings (year-end) (megawatts)	2,278	2,583	2,663	2,663	2,663
Maximum Peak-Hour Demand (megawatts):					
Winter	2,033	2,488	2,684	1,729	2,130
Summer	2,503	2,491	2,424	2,356	2,344
Annual Load Factor (percent)	54.7	54.9	51.1	55.9	56.3
Plant Availability Fossil-Steam (percent)	81.0	88.3	89.4	92.8	82.5
Source of Energy Supply (percent):					
Coal	31.0	33.5	44.5	36.4	34.6
Gas	23.2	25.6	22.2	23.0	23.5
Purchased power —					
From non-affiliates	41.1	30.4	28.9	37.0	40.2
From affiliates	4.7	10.5	4.4	3.6	1.7
Total	100.0	100.0	100.0	100.0	100.0

MISSISSIPPI POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Mississippi Power Company 2016 Annual Report

The management of Mississippi Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2016 .

/s/ Anthony L. Wilson
Anthony L. Wilson
Chairman, President, and Chief Executive Officer

/s/ Moses H. Feagin
Moses H. Feagin
Vice President, Chief Financial Officer, and Treasurer

February 21, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Mississippi Power Company

We have audited the accompanying balance sheets and statements of capitalization of Mississippi Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2016 and 2015 , and the related statements of operations, comprehensive income (loss), common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2016 . These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-427 to II-475) present fairly, in all material respects, the financial position of Mississippi Power Company as of December 31, 2016 and 2015 , and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016 , in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 to the financial statements, the Mississippi Public Service Commission rate recovery process associated with the Kemper Integrated Coal Gasification Combined Cycle Project may have a material impact on the Company's financial statements.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 21, 2017

DEFINITIONS

Term	Meaning
2012 MPSC CPCN Order	A detailed order issued by the Mississippi PSC in April 2012 confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing acquisition, construction, and operation of the Kemper IGCC
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ARO	Asset retirement obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Baseload Act	State of Mississippi legislation designed to enhance the Mississippi PSC's authority to facilitate development and construction of baseload generation in the State of Mississippi
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
CPCN	Certificate of public convenience and necessity
CWIP	Construction work in progress
DOE	U.S. Department of Energy
ECM	Energy cost management clause
ECO	Environmental compliance overview
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	U.S. generally accepted accounting principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IGCC	Integrated coal gasification combined cycle
IRS	Internal Revenue Service
ITC	Investment tax credit
Kemper IGCC	IGCC facility under construction in Kemper County, Mississippi
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
Mirror CWIP	A regulatory liability used by Mississippi Power to record customer refunds resulting from a 2015 Mississippi PSC order
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MPUS	Mississippi Public Utilities Staff
MRA	Municipal and Rural Associations
MW	Megawatt
OCI	Other comprehensive income
PEP	Performance evaluation plan
Plant Daniel Units 3 and 4	Combined cycle Units 3 and 4 at Plant Daniel
power pool	The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission

DEFINITIONS
(continued)

Term	Meaning
ROE	Return on equity
S&P	S&P Global Ratings, a division of S&P Global Inc.
scrubber	Flue gas desulfurization system
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
SMEPA	South Mississippi Electric Power Association (now known as Cooperative Energy)
Southern Company	The Southern Company
Southern Company Gas	Southern Company Gas (formerly known as AGL Resources Inc.) and its subsidiaries
Southern Company system	Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), Southern Electric Generating Company, Southern Nuclear, SCS, Southern LINC, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries
Southern LINC	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
SRR	System Restoration Rider
traditional electric operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power Company

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Mississippi Power Company 2016 Annual Report

OVERVIEW

Business Activities

Mississippi Power Company (the Company) operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located within the State of Mississippi and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of providing electric service. These factors include the Company's ability to maintain and grow energy sales and to operate in a constructive regulatory environment that provides timely recovery of prudently-incurred costs. These costs include those related to the completion and operation of the Kemper IGCC, projected long-term demand growth, reliability, fuel, and stringent environmental standards, as well as ongoing capital expenditures required for maintenance and restoration following major storms. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

The Company continues to progress toward completing the construction and start-up of the Kemper IGCC, which was approved by the Mississippi PSC in the 2010 CPCN proceedings, subject to a construction cost cap of $2.88 billion, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (Initial DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when the Company demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions). The current cost estimate for the Kemper IGCC in total is approximately $6.99 billion , which includes approximately $5.64 billion of costs subject to the construction cost cap and is net of the $137 million in additional grants from the DOE received on April 8, 2016 (Additional DOE Grants), which are expected to be used to reduce future rate impacts to customers. The Company does not intend to seek any rate recovery for any related costs that exceed the $ 2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. The Company recorded pre-tax charges to income for revisions to the cost estimate subject to the construction cost cap totaling $348 million ($215 million after tax), $365 million ($226 million after tax), and $868 million ($536 million after tax) in 2016 , 2015 , and 2014 , respectively. Since 2012, in the aggregate, the Company has incurred charges of $2.76 billion ($1.71 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2016 . The current cost estimate includes costs through March 15, 2017.

In addition to the current construction cost estimate, the Company is identifying potential improvement projects that ultimately may be completed subsequent to placing the remainder of the Kemper IGCC in service. If completed, such improvement projects would be expected to enhance plant performance, safety, and/or operations. As of December 31, 2016, approximately $12 million of related potential costs has been included in the estimated loss on the Kemper IGCC. Other projects have yet to be fully evaluated, have not been included in the current cost estimate, and may be subject to the $2.88 billion cost cap. Any further changes in the estimated costs of the Kemper IGCC subject to the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the Company's statements of income and these changes could be material.

The expected completion date of the Kemper IGCC at the time of the Mississippi PSC's approval in 2010 was May 2014. The combined cycle and the associated common facilities portion of the Kemper IGCC were placed in service in August 2014. The remainder of the plant, including the gasifiers and the gas clean-up facilities, represents first-of-a-kind technology. The initial production of syngas began on July 14, 2016 for gasifier "B" and on September 13, 2016 for gasifier "A." The Company achieved integrated operation of both gasifiers on January 29, 2017, including the production of electricity from syngas in both combustion turbines. The Company subsequently completed a brief outage to repair and make modifications to further improve the plant's ability to achieve sustained operations sufficient to support placing the plant in service for customers. Efforts to reach sustained operation of both gasifiers and production of electricity from syngas in both combustion turbines are in process. The plant has produced and captured CO_2 , and has produced sulfuric acid and ammonia, all of acceptable quality under the related off-take agreements. On February 20, 2017, the Company determined gasifier "B," which has been producing syngas over 60% of the time since early November 2016, requires an outage to remove ash deposits from its ash removal system. Gasifier "A" and combustion turbine "A" are expected to remain in operation, producing electricity from syngas, as well as producing chemical by-products. As a result, the Company currently expects the remainder of the Kemper IGCC, including both gasifiers, will be placed in service by mid-March 2017.

Upon placing the remainder of the plant in service, the Company will be primarily focused on completing the regulatory cost recovery process. In December 2015, the Mississippi PSC issued an order (In-Service Asset Rate Order), based on a stipulation

(2015 Stipulation) between the Company and the MPUS, authorizing rates that provide for the recovery of approximately $126 million annually related to Kemper IGCC assets previously placed in service.

On August 17, 2016, the Mississippi PSC established a discovery docket to manage all filings related to Kemper IGCC prudence issues. On October 3, 2016 and November 17, 2016, the Company made filings in this docket including a review and explanation of differences between the Kemper IGCC project estimate set forth in the 2010 CPCN proceedings and the most recent Kemper IGCC project estimate, as well as comparisons of current cost estimates and current expected plant operational parameters to the estimates presented in the 2010 CPCN proceedings for the first five years after the Kemper IGCC is placed in service. Compared to amounts presented in the 2010 CPCN proceedings, operations and maintenance expenses have increased an average of $105 million annually and maintenance capital has increased an average of $44 million annually for the first full five years of operations for the Kemper IGCC. Additionally, while the current estimated operational availability estimates reflect ultimate results similar to those presented in the 2010 CPCN proceedings, the ramp up period for the current estimates reflects a lower starting point and a slower escalation rate.

In the fourth quarter 2016, as a part of the Integrated Resource Plan process, the Southern Company system completed its regular annual updated fuel forecast, the 2017 Annual Fuel Forecast. This updated fuel forecast reflected significantly lower long-term estimated costs for natural gas than were previously projected. As a result of the updated long-term natural gas forecast, as well as the revised operating expense projections reflected in the discovery docket filings, on February 21, 2017, the Company filed an updated project economic viability analysis of the Kemper IGCC as required under the 2012 MPSC CPCN Order. The project economic viability analysis measures the life cycle economics of the Kemper IGCC compared to feasible alternatives, natural gas combined cycle generating units, under a variety of scenarios and considering fuel, operating and capital costs, and operating characteristics, as well as federal and state taxes and incentives. The reduction in the projected long-term natural gas prices in the 2017 Annual Fuel Forecast and, to a lesser extent, the increase in the estimated Kemper IGCC operating costs, negatively impact the updated project economic viability analysis.

After the remainder of the plant is placed in service, AFUDC equity of approximately $11 million per month will no longer be recorded in income, and the Company expects to incur approximately $25 million per month in depreciation, taxes, operations and maintenance expenses, interest expense, and regulatory costs in excess of current rates. The Company expects to file a request for authority from the Mississippi PSC and the FERC to defer all Kemper IGCC costs incurred after the in-service date that cannot be capitalized, are not included in current rates, and are not required to be charged against earnings as a result of the $2.88 billion cost cap until such time as the Mississippi PSC completes its review and includes the resulting allowable costs in rates. In the event that the Mississippi PSC does not grant the Company's request for an accounting order, these monthly expenses will be charged to income as incurred and will not be recoverable through rates. The ultimate outcome of this matter cannot now be determined but could have a material impact on the Company's result of operations, financial condition, and liquidity.

The Company is required to file a rate case to address Kemper IGCC cost recovery by June 3, 2017 (2017 Rate Case). Costs incurred through December 31, 2016 totaled $6.73 billion, net of the Initial and Additional DOE Grants. Of this total, $2.76 billion of costs has been recognized through income as a result of the $2.88 billion cost cap, $0.83 billion is included in retail and wholesale rates for the assets in service, and the remainder will be the subject of the 2017 Rate Case to be filed with the Mississippi PSC and expected subsequent wholesale MRA rate filing with the FERC. The Company continues to believe that all costs related to the Kemper IGCC have been prudently incurred in accordance with the requirements of the 2012 MPSC CPCN Order. The Company also recognizes significant areas of potential challenge during future regulatory proceedings (and any subsequent, related legal challenges) exist. As described further herein, these challenges include, but are not limited to, prudence issues associated with capital costs, financing costs (AFUDC), and future operating costs, net of chemical revenues; potential operating parameters; income tax issues; costs deferred as regulatory assets; and the 15% portion of the project previously contracted to SMEPA.

Although the 2017 Rate Case has not yet been filed and is subject to future developments with either the Kemper IGCC or the Mississippi PSC, consistent with its approach in the 2013 and 2015 rate proceedings in accordance with the law passed in 2013 authorizing multi-year rate plans, the Company is developing both a traditional rate case requesting full cost recovery of the $3.31 billion (net of $137 million in Additional DOE Grants) not currently in rates and a rate mitigation plan that together represent the Company's probable filing strategy. The Company also expects that timely resolution of the 2017 Rate Case will likely require a negotiated settlement agreement. In the event an agreement acceptable to both the Company and the MPUS (and other parties) can be negotiated and ultimately approved by the Mississippi PSC, it is reasonably possible that full regulatory recovery of all Kemper IGCC costs will not occur. The impact of such an agreement on the Company's financial statements would depend on the method, amount, and type of cost recovery ultimately excluded. Certain costs, including operating costs, would be recorded to income in the period incurred, while other costs, including investment-related costs, would be charged to income when it is probable they will not be recovered and the amounts can be reasonably estimated. In the event an agreement acceptable to the

parties cannot be reached, the Company intends to fully litigate its request for full recovery through the Mississippi PSC regulatory process and any subsequent legal challenges.

The Company has evaluated various scenarios in connection with its processes to prepare the 2017 Rate Case and has recognized an additional $80 million charge to income, which is the estimated minimum probable amount of the $3.31 billion of Kemper IGCC costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017. Given the variety of potential scenarios and the uncertainty of the outcome of future regulatory proceedings with the Mississippi PSC (and any subsequent related legal challenges), the ultimate outcome of these matters cannot now be determined but could result in further charges that could have a material impact on the Company's results of operations, financial condition, and liquidity.

Southern Company and the Company are defendants in various lawsuits that allege improper disclosure about the Kemper IGCC. While the Company believes that these lawsuits are without merit, an adverse outcome could have a material impact on the Company's results of operations, financial condition, and liquidity. In addition, the SEC is conducting a formal investigation of Southern Company and the Company concerning the estimated costs and expected in-service date of the Kemper IGCC. Southern Company and the Company believe the investigation is focused primarily on periods subsequent to 2010 and on accounting matters, disclosure controls and procedures, and internal controls over financial reporting associated with the Kemper IGCC. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" and "Other Matters" herein for additional information.

As of December 31, 2016 , the Company's current liabilities exceeded current assets by approximately $371 million primarily due to $551 million in promissory notes to Southern Company which mature in December 2017, $35 million in senior notes which mature in November 2017, and $63 million in short-term debt. The Company expects the funds needed to satisfy the promissory notes to Southern Company will exceed amounts available from operating cash flows, lines of credit, and other external sources. Accordingly, the Company intends to satisfy these obligations through loans and/or equity contributions from Southern Company. Specifically, the Company has been informed by Southern Company that, in the event sufficient funds are not available from external sources, Southern Company intends to (i) extend the maturity of the $551 million in promissory notes and (ii) provide Mississippi Power with loans and/or equity contributions sufficient to fund the remaining indebtedness scheduled to mature and other cash needs over the next 12 months. Therefore, the Company's financial statement presentation contemplates continuation of the Company as a going concern as a result of Southern Company's anticipated ongoing financial support of the Company, consistent with the requirements of ASU 2014-15 (as defined herein). See FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" herein and Notes 1 and 6 to the financial statements for additional information.

The Company continues to focus on several key performance indicators, including the construction, start-up, and rate recovery of the Kemper IGCC.

In recognition that the Company's long-term financial success is dependent upon how well it satisfies its customers' needs, the Company's retail base rate mechanism, PEP, includes performance indicators that directly tie customer service indicators to the Company's allowed return. PEP measures the Company's performance on a 10-point scale as a weighted average of results in three areas: average customer price, as compared to prices of other regional utilities (weighted at 40%); service reliability, measured in percentage of time customers had electric service (40%); and customer satisfaction, measured in a survey of residential customers (20%). See Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for more information on PEP.

In addition to the PEP performance indicators, the Company focuses on other performance measures, including broader measures of customer satisfaction, plant availability, system reliability, and net income after dividends on preferred stock.

The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys to evaluate the Company's results and generally targets the top quartile in measuring performance.

See RESULTS OF OPERATIONS herein for information on the Company's financial performance.

Earnings

The Company's net loss after dividends on preferred stock was $50 million in 2016 compared to $8 million in 2015 . The change in 2016 was primarily the result of higher pre-tax charges of $428 million ($264 million after tax) in 2016 compared to pre-tax charges of $365 million ($226 million after tax) in 2015 for estimated losses on the Kemper IGCC. The decrease in net income was partially offset by an increase in retail revenues due to the implementation of rates in September 2015 for certain Kemper IGCC in-service assets, partially offset by a decrease in wholesale revenues. The increase in revenues was partially offset by an

increase in interest expense in 2016 compared to 2015 due to the termination of an asset purchase agreement between the Company and SMEPA in May 2015 and an increase in operations and maintenance expenses.

The Company's net loss after dividends on preferred stock was $8 million in 2015 compared to $329 million in 2014 . The change in 2015 was primarily the result of lower pre-tax charges of $365 million ($226 million after tax) in 2015 compared to pre-tax charges of $868 million ($536 million after tax) in 2014 for revisions of estimated costs expected to be incurred on the Company's construction of the Kemper IGCC above the $2.88 billion cost cap established by the Mississippi PSC, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. The reduction in net loss was also related to an increase in retail base revenues, due to the implementation of rates for certain Kemper IGCC assets placed in service that became effective with the first billing cycle in September (on August 19), and a decrease in interest expense primarily due to the termination of an asset purchase agreement between the Company and SMEPA in May 2015, partially offset by increases in income taxes due to a reduced net loss.

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

RESULTS OF OPERATIONS

A condensed statement of operations follows:

	Amount	Increase (Decrease) from Prior Year	
	2016	**2016**	2015
		(in millions)	
Operating revenues	**$ 1,163**	**$ 25**	$ (105)
Fuel	**343**	**(100)**	(131)
Purchased power	**34**	**22**	(31)
Other operations and maintenance	**312**	**38**	3
Depreciation and amortization	**132**	**9**	26
Taxes other than income taxes	**109**	**15**	15
Estimated loss on Kemper IGCC	**428**	**63**	(503)
Total operating expenses	**1,358**	**47**	(621)
Operating income	**(195)**	**(22)**	516
Allowance for equity funds used during construction	**124**	**14**	(26)
Interest expense, net of amounts capitalized	**74**	**67**	(38)
Other income (expense), net	**(7)**	**1**	6
Income taxes (benefit)	**(104)**	**(32)**	213
Net income (loss)	**(48)**	**(42)**	321
Dividends on preferred stock	**2**	**—**	—
Net loss after dividends on preferred stock	**$ (50)**	**$ (42)**	$ 321

Operating Revenues

Operating revenues for 2016 were $1.2 billion , reflecting a $25 million increase from 2015 . Details of operating revenues were as follows:

	Amount	
	2016	2015
	(in millions)	
Retail — prior year	**$ 776**	$ 795
Estimated change resulting from —		
Rates and pricing	**96**	61
Sales decline	**(4)**	(3)
Weather	**8**	(1)
Fuel and other cost recovery	**(17)**	(76)
Retail — current year	**859**	776
Wholesale revenues —		
Non-affiliates	**261**	270
Affiliates	**26**	76
Total wholesale revenues	**287**	346
Other operating revenues	**17**	16
Total operating revenues	**$ 1,163**	$ 1,138
Percent change	**2.2%**	(8.4)%

Total retail revenues for 2016 increased $83 million , or 10.7% , compared to 2015 primarily due to changes in rates and pricing of $96 million partially offset by a net decrease in fuel and other cost recovery of $17 million. Total retail revenues for 2015 decreased $19 million, or 2.4%, compared to 2014 primarily due to a lower fuel cost recovery. This decrease was partially offset by changes in rates and pricing of $61 million.

Revenues associated with changes in rates and pricing increased $96 million in 2016 and $61 million in 2015 , primarily due to the implementation of rates for certain Kemper IGCC in-service assets effective in September 2015 and an annual ECO rate increase of $22 million collected from September through December 2016.

See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Compliance Overview" and "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" for additional information. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales and weather.

Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the energy component of purchased power costs, and do not affect net income. Recoverable fuel costs include fuel and purchased power expenses reduced by the fuel and emissions portion of wholesale revenues from energy sold to customers outside the Company's service territory. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information.

Wholesale revenues from power sales to non-affiliated utilities, including FERC-regulated MRA sales as well as market-based sales, were as follows:

	2016	2015	2014
		(in millions)	
Capacity and other	**$ 157**	$ 158	$ 160
Energy	**104**	112	163
Total non-affiliated	**$ 261**	$ 270	$ 323

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation. Increases and

decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. In addition, the Company provides service under long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 19.8% of the Company's total operating revenues in 2016 and are largely subject to rolling 10-year cancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

Wholesale revenues from sales to non-affiliates decreased $9 million , or 3.3% , in 2016 compared to 2015 primarily as a result of an $8 million decrease in energy revenues, of which $10 million was associated with lower fuel prices, offset by an increase in KWH sales of $2 million. Wholesale revenues from sales to non-affiliates decreased $53 million, or 16.4%, in 2015 compared to 2014 primarily as a result of a $51 million decrease in energy revenues, of which $13 million was associated with a decrease in KWH sales and $38 million was associated with lower fuel prices.

Short-term opportunity energy sales are also included in sales for resale to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy.

Wholesale revenues from sales to affiliates will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Wholesale revenues from sales to affiliates decreased $50 million , or 65.8% , in 2016 compared to 2015 primarily due to a $50 million decrease in energy revenues of which $4 million was associated with lower fuel prices and $46 million was associated with a decrease in KWH sales as a result of lower cost generation available in the Southern Company system. Wholesale revenues from sales to affiliates decreased $31 million, or 29.0%, in 2015 compared to 2014 primarily due to a $31 million decrease in energy revenues of which $28 million was associated with lower fuel prices and $3 million was associated with a decrease in KWH sales.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2016 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2016	**2016**	2015	**2016** (*)	2015 (*)
	(in millions)				
Residential	**2,051**	**1.3 %**	(4.8)%	**(2.4)%**	(0.4)%
Commercial	**2,842**	**1.3**	(1.9)	**(2.2)**	(0.4)
Industrial	**4,906**	**(1.0)**	0.3	**(1.6)**	0.8
Other	**39**	**(1.3)**	(2.1)	**(1.3)**	(2.1)
Total retail	**9,838**	**0.1**	(1.4)	**(1.9)%**	0.2 %
Wholesale					
Non-affiliated	**3,920**	**1.7**	(8.1)		
Affiliated	**1,108**	**(60.5)**	(3.2)		
Total wholesale	**5,028**	**(24.5)**	(6.1)		
Total energy sales	**14,866**	**(9.8)%**	(3.4)%		

(*) In the first quarter 2015, the Company updated the methodology to estimate the unbilled revenue allocation among customer classes. This change did not have a material impact on net income. The KWH sales variances in the above table reflect an adjustment to the estimated allocation of the Company's unbilled 2014 and first quarter 2015 KWH sales among customer classes that is consistent with the actual allocation in 2015 and 2016, respectively. Without this adjustment, 2016 weather-adjusted residential sales decreased 1.0%, commercial sales decreased 0.6%, and industrial KWH sales decreased 1.0% as compared to the corresponding period in 2015. Without this adjustment, 2015 weather-adjusted residential sales decreased 1.8%, commercial sales decreased 2.1%, and industrial KWH sales increased 0.3% as compared to the corresponding period in 2014.

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales increased 0.1% in 2016 as compared to the prior year. This increase was primarily the result of warmer weather in the third quarter 2016 as compared to the corresponding period in 2015 . Weather-adjusted residential and commercial KWH sales decreased primarily due to decreased customer usage partially offset by customer

growth. The decrease in industrial KWH energy sales was primarily due to planned and unplanned outages by large industrial customers.

Retail energy sales decreased 1.4% in 2015 as compared to the prior year. This decrease was primarily the result of milder weather in the first and fourth quarters of 2015 as compared to the corresponding periods in 2014. Weather-adjusted residential and commercial KWH sales decreased primarily due to decreased customer usage partially offset by customer growth. Household income, one of the primary drivers of residential customer usage, had modest growth in 2015. The increase in industrial KWH energy sales was primarily due to expanded operation by many industrial customers.

Wholesale energy sales to non-affiliates decreased in 2016 compared to 2015 primarily due to lower fuel prices which was partially offset by an increased opportunity sales to the external market based on higher demand. Wholesale energy sales to non-affiliates decreased in 2015 compared to 2014 primarily due to decreased opportunity sales to the external market based on lower demand which was offset by lower fuel prices.

Wholesale energy sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company and the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation.

Wholesale energy sales to affiliates decreased in 2016 compared to 2015 primarily due to lower fuel cost and reduced sales to affiliate companies. Wholesale energy sales to affiliates decreased in 2015 compared to 2014 primarily due to lower fuel cost and reduced sales to affiliate companies.

Fuel and Purchased Power Expenses

Fuel costs constitute one of the single largest expenses for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's generation and purchased power were as follows:

	2016	2015	2014
Total generation *(in millions of KWHs)*	**14,514**	17,014	16,881
Total purchased power *(in millions of KWHs)*	**1,574**	539	886
Sources of generation *(percent)* –			
Coal	**9**	17	42
Gas	**91**	83	58
Cost of fuel, generated *(in cents per net KWH)* –			
Coal	**3.91**	3.71	3.96
Gas	**2.41**	2.58	3.37
Average cost of fuel, generated *(in cents per net KWH)*	**2.55**	2.78	3.64
Average cost of purchased power *(in cents per net KWH)*	**3.07**	2.17	4.85

Fuel and purchased power expenses were $377 million in 2016 , a decrease of $78 million, or 17.1%, as compared to the prior year. The decrease was primarily due to a $20 million decrease in the cost of natural gas and a decrease of $82 million due to a decrease in the volume of KWH generation, partially offset by a $12 million increase in KWHs purchased and a $12 million increase in the cost of coal. Fuel and purchased power expenses were $455 million in 2015, a decrease of $162 million, or 26.3%, as compared to the prior year. The decrease was primarily due to a $125 million decrease in the cost of fuel and purchased power and a decrease of $183 million in the volume of KWHs generated by coal and purchased, partially offset by a $146 million increase in the volume of KWHs generated by gas.

Fuel and purchased power energy transactions do not have a significant impact on earnings, since energy expenses are generally offset by energy revenues through the Company's fuel cost recovery clauses. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein and Note 1 to the financial statements under "Fuel Costs" for additional information.

Fuel

Fuel expense decreased $100 million , or 22.6% , in 2016 compared to 2015 due to an 8.2% decrease in the average cost of fuel per KWH generated and a 15.5% decrease in the volume of KWHs generated. Fuel expense decreased $131 million, or 22.8%, in

2015 compared to 2014. The decrease was the result of a 23.6% decrease in the average cost of fuel per KWH generated, partially offset by a 0.9% increase in the volume of KWHs generated.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates was flat in 2016 compared to 2015. Purchased power expense from non-affiliates decreased $13 million, or 72.2%, in 2015 compared to 2014. The decrease was primarily the result of a 72.4% decrease in the average cost per KWH purchased.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation.

Purchased Power - Affiliates

Purchased power expense from affiliates increased $22 million , or 314.3% , in 2016 compared to 2015 . The increase in 2016 was primarily the result of a 338.4% increase in the volume of KWHs purchased due to the availability of lower cost energy as compared to the cost of self-generation and a slight increase in the average cost per KWH purchased compared to 2015. Purchased power expense from affiliates decreased $18 million, or 72.0%, in 2015 compared to 2014. The decrease in 2015 was primarily the result of a 58.3% decrease in the volume of KWHs purchased and a 36.9% decrease in the average cost per KWH purchased compared to 2014.

Energy purchases from affiliates will vary depending on demand for energy and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, as approved by the FERC.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses increased $38 million , or 13.9% , in 2016 compared to the prior year. The increase was primarily due to a $28 million increase in operations and maintenance expenses related to the combined cycle and the associated common facilities portion of the Kemper IGCC, $10 million in amortization of prior operations and maintenance expense deferrals that the Company began recognizing in connection with rates associated with the Kemper IGCC in-service assets, and a $7 million increase in transmission and distribution expenses primarily related to overhead line maintenance and vegetation management, partially offset by a $9 million decrease in generation outage costs.

Other operations and maintenance expenses increased $3 million, or 1.1%, in 2015 compared to the prior year. The increase was primarily related to a $7 million increase in employee compensation and benefits, including pension costs, and a $6 million increase in generation maintenance expenses related to the combined cycle and the associated common facilities portion of the Kemper IGCC. See Note 2 to the financial statements for additional information on pension costs. Beginning in the third quarter 2015, in connection with the implementation of rates associated with the Kemper IGCC, the Company began expensing certain ongoing project costs associated with Kemper IGCC assets placed in service that previously were deferred as regulatory assets. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2015 Rate Case" and " – Regulatory Assets and Liabilities" herein for additional information. These increases in 2015 were partially offset by decreases of $4 million in transmission and distribution expenses primarily related to overhead line maintenance and vegetation management, $3 million in generation maintenance expenses primarily due to lower outage costs, and $2 million in overtime labor.

Depreciation and Amortization

Depreciation and amortization increased $9 million , or 7.3% , in 2016 compared to 2015 primarily due to $32 million of additional regulatory asset amortization related to the In-Service Asset Rate Order, ECO plan, and Mercury and Air Toxics Standards (MATS) rule compliance, $13 million associated with Kemper IGCC deferrals primarily related to depreciation deferrals in 2015, and $9 million of depreciation for additional plant in service assets primarily associated with the Plant Daniel scrubbers. These increases were partially offset by $23 million of amortization of regulatory deferrals related to the In-Service Asset Rate Order and a $22 million deferral associated with the implementation of revised ECO plan rates with the first billing cycle for September 2016.

Depreciation and amortization increased $26 million, or 26.8%, in 2015 compared to 2014 primarily due to an $18 million increase in depreciation related to an increase in assets in service and an increase in the depreciation rates, a $16 million increase due to amortization of regulatory assets associated with the Kemper IGCC, and a $2 million increase resulting from the estimated 2015 cost of capital as agreed in the In-Service Asset Rate Order. These increases were partially offset by decreases of $5 million

in ECO plan amortization, $3 million in Kemper IGCC combined cycle cost deferrals, and $2 million in deferrals associated with the purchase of Plant Daniel Units 3 and 4. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities" herein for additional information.

See Note 1 to the financial statements under "Depreciation and Amortization" and Note 3 to the financial statements under "FERC Matters," "Retail Regulatory Matters – Environmental Compliance Overview Plan," and "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $15 million , or 16.0% , in 2016 compared to 2015 primarily due to increases in ad valorem taxes of $10 million, related to an increase in the assessed value of property, as well as increases in franchise taxes of $5 million, related to increased operating revenue. Taxes other than in come taxes increased $15 million, or 19.0%, in 2015 compared to 2014 primarily as a result of a $12 million increase in ad valorem taxes and a $4 million increase in franchise taxes, partially offset by a $1 million decrease in payroll taxes.

The retail portion of ad valorem taxes is recoverable under the Company's ad valorem tax cost recovery clause and, therefore, does not affect net income.

Estimated Loss on Kemper IGCC

Estimated probable losses on the Kemper IGCC of $428 million , $365 million, and $868 million were recorded in 2016 , 2015 , and 2014, respectively, to reflect revisions of estimated costs expected to be incurred on the construction of the Kemper IGCC in excess of the $2.88 billion cost cap established by the Mississippi PSC, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. The 2016 loss also reflects $80 million associated with the estimated minimum probable amount of costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017.

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

Allowance for Equity Funds Used During Construction

AFUDC equity increased $14 million , or 12.7% , in 2016 as compared to 2015 . The increase in 2016 was primarily due to a higher AFUDC rate and an increase in Kemper IGCC CWIP subject to AFUDC, partially offset by placing the Plant Daniel scrubbers in service in November 2015. AFUDC equity decreased $26 million, or 19.1%, in 2015 as compared to 2014. The decrease in 2015 was primarily due to a reduction in the AFUDC rate driven by an increase in short-term borrowings and placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service in August 2014. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Allowance for Funds Used During Construction" herein and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $67 million in 2016 compared to 2015 . The increase was primarily due to an increase of $31 million of interest on deposits resulting from the 2015 reversal of interest associated with the termination of an asset purchase agreement between the Company and SMEPA in May 2015; a $20 million increase due to additional long-term debt and a $30 million decrease in amounts capitalized primarily resulting from $17 million of capitalized interest and the amortization of $13 million in interest deferrals in accordance with the In-Service Asset Rate Order. These net increases were partially offset by a decrease of $16 million in interest accrued on the Mirror CWIP liability prior to refund in 2015.

Interest expense, net of amounts capitalized decreased $38 million, or 84.4%, in 2015 compared to 2014. The decrease was primarily due to a $58 million decrease related to the termination of an asset purchase agreement between the Company and SMEPA in May 2015 which required the return of SMEPA's deposits at a lower rate of interest than accrued, a $5 million decrease associated with amended tax returns, and a $2 million decrease associated with the redemption of long-term debt in 2015. These decreases were partially offset by increases in interest expense of $10 million associated with additional issuances of debt in 2015, $9 million associated with unrecognized tax benefits, and $5 million related to the Mirror CWIP refund, partially offset by a $3 million decrease in AFUDC debt. See Note 5 to the financial statements for additional information.

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle – Termination of Proposed Sale of Undivided Interest to SMEPA" for more information.

Income Taxes (Benefit)

Income tax benefits increased $32 million , or 44.4% , in 2016 compared to 2015 primarily as a result of an increase in the estimated probable losses on the Kemper IGCC and an increase in AFUDC equity, which is non-taxable.

Income tax benefits decreased $213 million, or 74.7%, in 2015 compared to 2014 primarily resulting from the reduction in pre-tax losses related to the estimated probable losses on the Kemper IGCC.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located in southeast Mississippi and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Mississippi PSC under cost-based regulatory principles. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. See "FERC Matters" herein, ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Utility Regulation" herein, and Note 3 to the financial statements for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to recover its prudently-incurred costs, including those related to the remainder of the Kemper IGCC costs not included in current rates, in a timely manner during a time of increasing costs, its ability to prevail against legal challenges associated with the Kemper IGCC, and the completion and subsequent operation of the Kemper IGCC in accordance with any operational parameters that may be adopted by the Mississippi PSC. Future earnings will be driven primarily by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies and increasing volumes of electronic commerce transactions. Earnings are subject to a variety of other factors. These factors include weather, competition, developing new and maintaining existing energy contracts and associated load requirements with other utilities and other wholesale customers, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Demand for electricity is primarily driven by economic growth. The pace of economic growth and electricity demand may be affected by changes in regional and global economic conditions, which may impact future earnings. Current proposals related to potential tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals is dependent on the final form of any legislation enacted and the related transition rules and cannot be determined at this time, but could have a material impact on the Company's financial statements.

The Company provides service under long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 19.8% of the Company's total operating revenues in 2016 and are largely subject to rolling 10-year cancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis or through long-term wholesale agreements. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are completed. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; the Migratory Bird Treaty Act; the Bald and Golden Eagle Protection Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2016 , the Company had invested approximately $634 million in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $17 million, $94 million, and $118 million for 2016 , 2015 , and 2014 , respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $127 million from 2017 through 2021 , with annual totals of approximately $11 million, $5 million, $24 million, $29 million, and $58 million for 2017 , 2018 , 2019 , 2020 , and 2021 , respectively. These estimated expenditures do not include any potential capital expenditures that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from existing, new, modified, or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Company also anticipates costs associated with ash pond closure and ground water monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are reflected in the Company's ARO liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations, including the environmental regulations described below; the time periods over which compliance with regulations is required; individual state implementation of regulations, as applicable; the outcome of any legal challenges to the environmental rules; any additional rulemaking activities in response to legal challenges and court decisions; the cost, availability, and existing inventory of emissions allowances; the impact of future changes in generation and emissions-related technology; the Company's fuel mix; and environmental remediation requirements. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time. See "Retail Regulatory Matters – Environmental Compliance Overview Plan" herein for additional information.

Compliance with any new federal or state legislation or regulations relating to air, water, and land resources or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the Company's commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company.

In 2012, the EPA finalized the MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. The implementation strategy for the MATS rule included emission controls, retirements, and fuel conversions at affected units. All of the Company's units that are subject to the MATS rule completed the measures necessary to achieve compliance with this rule or were retired prior to or during 2016.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard (NAAQS). In 2008, the EPA adopted a revised eight-hour ozone NAAQS and published its final area designations in 2012. All areas within the Company's service territory have achieved attainment of the 2008 standard. In October 2015, the EPA published a more stringent eight-hour ozone NAAQS. This new standard could potentially require additional emission controls, improvements in control efficiency, and operational fuel changes and could affect the siting of new generating facilities. States were required to recommend area designations by October 2016, and no areas within the Company's service territory were proposed for designation as nonattainment.

The EPA regulates fine particulate matter concentrations through an annual and 24-hour average NAAQS, based on standards promulgated in 1997, 2006, and 2012. All areas in which the Company's generating units are located have been determined by the EPA to be in attainment with those standards.

In 2010, the EPA revised the NAAQS for sulfur dioxide (SO_2), establishing a new one-hour standard. No areas within the Company's service territory have been designated as nonattainment under this standard. However, in 2015, the EPA finalized a data requirements rule to support final EPA designation decisions for all remaining areas under the SO_2 standard, which could result in nonattainment designations for areas within the Company's service territory. Nonattainment designations could require additional reductions in SO_2 emissions and increased compliance and operational costs.

On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide (NO_x) emissions from power plants in two phases – Phase 1 in 2015 and Phase 2 in 2017. On October 26, 2016, the EPA published a final rule that updates the CSAPR ozone season NO_x program, beginning in 2017, and establishes more stringent ozone-season emissions budgets in Alabama and Mississippi. The State of Alabama is also in the CSAPR annual SO_2 and NO_x programs.

The EPA finalized regional haze regulations in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology to certain sources, including fossil fuel-fired generating facilities, built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter. On December 14, 2016, the EPA finalized revisions to the regional haze regulations. These regulations establish a deadline of July 31, 2021 for states to submit revised SIPs to the EPA demonstrating reasonable progress toward the statutory goal of achieving natural background conditions by 2064. State implementation of the reasonable progress requirements defined in this final rule could require further reductions in SO_2 or NO_x emissions.

In June 2015, the EPA published a final rule requiring certain states (including Alabama and Mississippi) to revise or remove the provisions of their SIPs relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM), and many states have submitted proposed SIP revisions in response to the rule.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. These regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates or through PPAs. The ultimate impact of the eight-hour ozone and SO_2 NAAQS, CSAPR, regional haze regulations, and SSM rule will depend on various factors, such as implementation, adoption, or other action at the state level, and the outcome of pending and/or future legal challenges, and cannot be determined at this time.

See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.

Water Quality

The EPA's final rule establishing standards for reducing effects on fish and other aquatic life caused by new and existing cooling water intake structures at existing power plants and manufacturing facilities became effective in 2014. The effect of this final rule will depend on the results of additional studies that are currently underway and implementation of the rule by regulators based on site-specific factors. National Pollutant Discharge Elimination System (NPDES) permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule.

In November 2015, the EPA published a final effluent guidelines rule which imposes stringent technology-based requirements for certain wastestreams from steam electric power plants. The revised technology-based limits and compliance dates will be incorporated into future renewals of NPDES permits at affected units and may require the installation and operation of multiple technologies sufficient to ensure compliance with applicable new numeric wastewater compliance limits. Compliance deadlines between November 1, 2018 and December 31, 2023 will be established in permits based on information provided for each applicable wastestream.

In 2015, the EPA and the U.S. Army Corps of Engineers jointly published a final rule revising the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs. The final rule significantly expands the scope of federal jurisdiction under the CWA and could have significant impacts on economic development projects which could affect customer demand growth. In addition, this rule could significantly increase permitting and regulatory requirements and costs associated with the siting of new facilities and the installation, expansion, and maintenance of transmission and distribution lines . The rule became effective in August 2015 but, in October 2015, the U.S. Court of Appeals for the Sixth Circuit issued an order staying implementation of the final rule. The case is held in abeyance pending review by the U.S. Supreme Court of challenges to the U.S. Court of Appeals for the Sixth Circuit's jurisdiction in the case.

These water quality regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions and decisions on infrastructure expansion and improvements. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The ultimate impact of these final rules will depend on various factors, such as pending and/or future legal challenges, compliance dates, and implementation of the rules, and cannot be determined at this time.

Coal Combustion Residuals

The Company currently manages two electric generating plants in Mississippi and is also part owner of a plant located in Alabama, each with onsite CCR storage units consisting of landfills and surface impoundments (CCR Units) . In addition to on-site storage, the Company also sells a portion of its CCR to third parties for beneficial reuse. Individual states regulate CCR and the States of Mississippi and Alabama each have their own regulatory requirements. The Company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

The CCR Rule became effective in October 2015. The CCR Rule regulates the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in CCR Units at active generating power plants. The CCR Rule does not automatically require closure of CCR Units but includes minimum criteria for active and inactive surface impoundments containing CCR and liquids, lateral expansions of existing units, and active landfills. Failure to meet the minimum criteria can result in the required closure of a CCR Unit. On December 16, 2016, President Obama signed the Water Infrastructure Improvements for the Nation Act (WIIN Act). The WIIN Act allows states to establish permit programs for implementing the CCR Rule, if the EPA approves the program, and allows for federal permits and EPA enforcement where a state permitting program does not exist.

Based on current cost estimates for closure and monitoring of ash ponds pursuant to the CCR Rule, the Company has recorded AROs related to the CCR Rule. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing with respect to compliance activities, the Company expects to continue to periodically update these estimates. The Company has posted closure and post-closure care plans to its public website as required by the CCR Rule; however, the ultimate impact of the CCR Rule will depend on the results of initial and ongoing minimum criteria assessments and the implementation of state or federal permit programs. On December 15, 2016, the Mississippi PSC granted a CPCN to the Company authorizing certain projects associated with complying with the CCR Rule. Additionally in this order, the Mississippi PSC also authorized the Company to recover any costs associated with the CPCN, including future monitoring costs, through the ECO plan rate. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information regarding the Company's AROs as of December 31, 2016.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up affected sites. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known impacted sites. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through its ECO clause. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

In October 2015, the EPA published two final actions that would limit CO_2 emissions from fossil fuel-fired electric generating units. One of the final actions contains specific emission standards governing CO_2 emissions from new, modified, and reconstructed units. The other final action, known as the Clean Power Plan, establishes guidelines for states to develop plans to meet EPA-mandated CO_2 emission rates or emission reduction goals for existing units. The EPA's final guidelines require state plans to meet interim CO_2 performance rates between 2022 and 2029 and final rates in 2030 and thereafter. At the same time, the EPA published a proposed federal plan and model rule that, when finalized, states can adopt or that would be put in place if a state either does not submit a state plan or its plan is not approved by the EPA. On February 9, 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan, pending disposition of petitions for review with the courts. The stay will remain in effect through the resolution of the litigation, including any review by the U.S. Supreme Court.

These guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions and decisions on infrastructure expansion and improvements . The Company's results of operations, cash flows, and financial condition could be significantly impacted if such

costs are not recovered through regulated rates or through PPAs. However, the ultimate financial and operational impact of the final rules on the Company cannot be determined at this time and will depend upon numerous factors, including the outcome of pending legal challenges, including legal challenges filed by the traditional electric operating companies, and any individual state implementation of the EPA's final guidelines in the event the rule is upheld and implemented.

In December 2015, parties to the United Nations Framework Convention on Climate Change – including the United States – adopted the Paris Agreement, which establishes a non-binding universal framework for addressing greenhouse gas emissions based on nationally determined contributions. It also sets in place a process for tracking progress toward the goals every five years. The ultimate impact of this agreement depends on its implementation by participating countries and cannot be determined at this time.

The EPA's greenhouse gas reporting rule requires annual reporting of greenhouse gas emissions expressed in terms of metric tons of CO_2 equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2015 greenhouse gas emissions were approximately 7 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2016 greenhouse gas emissions on the same basis is approximately 7 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation, the mix of fuel sources, and other factors.

FERC Matters

Municipal and Rural Associations Tariff

In 2013, the FERC accepted a settlement agreement entered into by the Company with its wholesale customers which approved, among other things, the same regulatory treatment for tariff ratemaking as the treatment approved for retail ratemaking by the Mississippi PSC for certain items. The regulatory treatment includes (i) approval to establish a regulatory asset for the portion of non-capitalizable Kemper IGCC-related costs which have been and will continue to be incurred during the construction period for the Kemper IGCC, (ii) authorization to defer as a regulatory asset, for the 10 -year period ending October 2021, the difference between the revenue requirement under the purchase option of Plant Daniel Units 3 and 4 (assuming a remaining 30 -year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into wholesale rates over the remaining life of Plant Daniel Units 3 and 4, and (iii) authority to defer in a regulatory asset costs related to the retirement or partial retirement of generating units as a result of environmental compliance rules.

In 2014, the Company reached, and the FERC accepted, a settlement agreement with its wholesale customers for an estimated annual increase in the MRA cost-based tariff of approximately $10 million , effective May 1, 2014. Included in this settlement agreement was a mechanism allowing the Company to adjust the wholesale revenue requirement in a subsequent rate proceeding in the event the Kemper IGCC, or any substantial portion thereof, was placed in service before or after December 1, 2014. Therefore, the Company recorded a regulatory asset as a result of a portion of the Kemper IGCC being placed in service prior to the projected date, which was fully amortized as of December 31, 2015. In May 2015, the FERC accepted a further settlement agreement between the Company and its wholesale customers to forgo a MRA cost-based electric tariff increase by, among other things, increasing the accrual of AFUDC and lowering the portion of CWIP in rate base, effective April 1, 2015, resulting in an estimated annual AFUDC increase of approximately $14 million , of which approximately $11 million is related to the Kemper IGCC.

On March 31, 2016, the Company reached a settlement agreement with its wholesale customers, which was subsequently approved by the FERC, for an increase in wholesale base revenues under the MRA cost-based electric tariff, primarily as a result of placing scrubbers for Plant Daniel Units 1 and 2 in service in November 2015. The settlement agreement became effective for services rendered beginning May 1, 2016, resulting in an estimated annual revenue increase of $7 million under the MRA cost-based electric tariff. Additionally, under the settlement agreement, the tariff customers agreed to similar regulatory treatment for MRA tariff ratemaking as the treatment approved for retail ratemaking under the In-Service Asset Rate Order. This regulatory treatment primarily includes (i) recovery of the Kemper IGCC assets currently operational and providing service to customers and other related costs, (ii) amortization of the Kemper IGCC-related regulatory assets included in rates under the settlement agreement over the 36 months ending April 30, 2019, (iii) Kemper IGCC-related expenses included in rates under the settlement agreement no longer being deferred and charged to expense, and (iv) removing all of the Kemper IGCC CWIP from rate base with a corresponding increase in accrual of AFUDC. The additional resulting AFUDC is estimated to be approximately $14 million through the Kemper IGCC's projected in-service date of mid-March 2017.

Fuel Cost Recovery

The Company has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective with the first billing cycle for September 2016, fuel rates decreased $11 million annually for wholesale MRA customers and $1 million annually for wholesale MB customers. At December 31, 2016 and 2015, the amount of over recovered wholesale MRA fuel costs were approximately $ 13 million and $24 million, respectively, which is included in over recovered regulatory clause liabilities, current in the balance sheets. Effective January 1, 2017, the wholesale MRA fuel rate increased $10 million annually.

The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on the Company's revenues or net income, but will affect cash flow.

Market-Based Rate Authority

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric operating companies' (including the Company's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies (including the Company) and Southern Power filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.

On December 9, 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. The traditional electric operating companies (including the Company) and Southern Power expect to make a compliance filing within 30 days accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

The ultimate outcome of these matters cannot be determined at this time.

Retail Regulatory Matters

General

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Mississippi PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased power, energy efficiency programs, ad valorem taxes, property damage, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates. See Note 3 to the financial statements under "Retail Regulatory Matters" and "Integrated Coal Gasification Combined Cycle" for additional information.

In 2012, the Mississippi PSC issued an order for the purpose of investigating and reviewing, for informational purposes only, the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. In 2013, the MPUS filed with the Mississippi PSC its report on the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. The ultimate outcome of this matter cannot be determined at this time.

Renewables

In November 2015, the Mississippi PSC issued orders approving three solar facilities for a combined total of approximately 105 MWs. The Company will purchase all of the energy produced by the solar facilities for the 25-year term under each of the three PPAs. The projects are expected to be in service by the second quarter 2017 and the resulting energy purchases are expected to be recovered through the Company's fuel cost recovery mechanism. The Company may retire the renewable energy credits (REC) generated on behalf of its customers or sell the RECs, separately or bundled with energy, to third parties.

Performance Evaluation Plan

The Company's retail base rates are set under the PEP, a rate plan approved by the Mississippi PSC. Two filings are made for each calendar year: the PEP projected filing, which is typically filed prior to the beginning of the year based on a projected revenue requirement, and the PEP lookback filing, which is filed after the end of the year and allows for review of the actual revenue requirement compared to the projected filing.

In 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. Later in 2011, the Company received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. In 2012, the Mississippi PSC issued an order canceling the Company's PEP lookback filing for 2011. I n 2013, the MPUS contested the Company's PEP lookback filing for 2012, which indicated a refund due to customers of $5 million . Unresolved matters related to the 2010 PEP lookback filing, which remain under review, also impact the 2012 PEP lookback filing.

In 2013, the Mississippi PSC approved the projected PEP filing for 2013, which resulted in a rate increase of 1.9% , or $15 million , annually, effective March 19, 2013. The Company may be entitled to $3 million in additional revenues related to 2013 as a result of the late implementation of the 2013 PEP rate increase.

In 2014, 2015, and 2016, the Company submitted its annual PEP lookback filings for the prior years, which for 2013 and 2014 each indicated no surcharge or refund and for 2015 indicated a $5 million surcharge. On July 12, 2016 and November 15, 2016, the Company submitted its annual projected PEP filings for 2016 and 2017, respectively, which each indicated no change in rates. The Mississippi PSC suspended each of these filings to allow more time for review.

In 2014, the Mississippi PSC issued an order for the purpose of investigating and reviewing the adoption of a uniform formula rate plan for the Company and other regulated electric utilities in Mississippi.

The ultimate outcome of these matters cannot be determined at this time.

Energy Efficiency

In 2013, the Mississippi PSC approved an energy efficiency and conservation rule requiring electric and gas utilities in Mississippi serving more than 25,000 customers to implement energy efficiency programs and standards.

On May 3, 2016, the Mississippi PSC issued an order approving the Company's Energy Efficiency Cost Rider Compliance filing, which reduced annual retail revenues by approximately $2 million effective with the first billing cycle for June 2016.

On November 30, 2016, the Company submitted its Energy Efficiency Cost Rider Compliance filing, which included an increase of $1 million in annual retail revenues. The ultimate outcome of this matter cannot be determined at this time.

See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Environmental Compliance Overview Plan

In 2012, the Mississippi PSC approved the Company's request for a CPCN to construct scrubbers on Plant Daniel Units 1 and 2, which were placed in service in November 2015. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. In 2014, the Company entered into a settlement agreement with the Sierra Club that, among other things, required the Sierra Club to dismiss or withdraw all pending legal and regulatory challenges to the issuance of the CPCN to construct scrubbers on Plant Daniel Units 1 and 2, which also occurred in 2014. In addition, and consistent with the Company's ongoing evaluation of recent environmental rules and regulations, the Company agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source Plant Sweatt Units 1 and 2 (80 MWs) no later than December 2018 (and the units were retired in July 2016). The Company also agreed that it would cease burning coal and other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and begin operating those units solely on natural gas no later than April 2015 (which occurred in April 2015) and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) no later than April 2016 (which occurred in February and March 2016, respectively) and begin operating those units solely on natural gas (which occurred in June and July 2016, respectively).

In accordance with a 2011 accounting order from the Mississippi PSC, the Company has the authority to defer in a regulatory asset for future recovery all plant retirement- or partial retirement-related costs resulting from environmental regulations. As of December 31, 2016, $17 million of Plant Greene County costs have been reclassified as regulatory assets and are expected to be recovered through the ECO plan and other existing cost recovery mechanisms over a period to be determined by the Mississippi PSC. The Mississippi PSC approved $41 million of costs that were reclassified to a regulatory asset associated with Plant Watson for amortization over a five -year period that began in July 2016. As a result, these decisions are not expected to have a material impact on the Company's financial statements.

On August 17, 2016, the Mississippi PSC approved the Company's revised ECO plan filing for 2016, which requested the maximum 2% annual increase in revenues, approximately $18 million , primarily related to the Plant Daniel Units 1 and 2 scrubbers being placed in service in November 2015. The revised rates became effective with the first billing cycle for September 2016. Approximately $22 million of related revenue requirements in excess of the 2% maximum was deferred for inclusion in the 2017 filing **.**

On February 14, 2017, the Company submitted its ECO plan filing for 2017, which requested an increase in annual revenues over 2016, capped at 2% of total retail revenues, of approximately $18 million , primarily related to the Plant Daniel Units 1 and 2 scrubbers placed in service in November 2015. The revenue requirement in excess of the 2% , approximately $27 million plus carrying costs, will be carried forward to the 2018 filing. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually. The Mississippi PSC approved the 2016 retail fuel cost recovery factor, effective January 5, 2016, which resulted in an annual revenue decrease of approximately $120 million . On August 17, 2016, the Mississippi PSC approved an additional decrease of $51 million annually in fuel cost recovery rates effective with the first billing cycle for September 2016. At December 31, 2016 and 2015, over recovered retail fuel costs were approximately $37 million and $71 million, respectively, which is included in over recovered regulatory clause liabilities, current in the balance sheets. On January 12, 2017, the Mississippi PSC approved the 2017 retail fuel cost recovery factor, effective February 2017 through January 2018, which will result in an annual revenue increase of approximately $55 million.

The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on the Company's revenues or net income, but will affect cash flow.

Ad Valorem Tax Adjustment

The Company establishes, annually, an ad valorem tax adjustment factor that is approved by the Mississippi PSC to collect the ad valorem taxes paid by the Company. On June 17, 2016, the Mississippi PSC approved the Company's annual ad valorem tax adjustment factor filing for 2016, which included an annual rate decrease of 0.07%, or $1 million in annual retail revenues, primarily due to the prior year over recovery.

System Restoration Rider

In October 2015, the Mississippi PSC approved the Company's 2015 SRR rate filing, which proposed that the SRR rate remain level at zero and the Company continue to accrue $3 million annually to the property damage reserve.

On February 1, 2016, the Company submitted its 2016 SRR rate filing which proposed no changes to either the SRR rate or the annual property damage reserve accrual. On February 19, 2016, the filing was suspended by the Mississippi PSC for review. The ultimate outcome of this matter cannot be determined at this time.

On February 3, 2017, the Company submitted its 2017 SRR rate filing, which proposed that the rate level remain at zero and the Company be allowed to accrue $4 million annually to the property damage reserve in 2017. The ultimate outcome of this matter cannot be determined at this time.

See Note 1 to the financial statements under "Provision for Property Damage" for additional information.

Storm Damage Cost Recovery

In connection with the damage associated with Hurricane Katrina, the Mississippi PSC authorized the issuance of system restoration bonds in 2006. In accordance with a Mississippi PSC order dated January 24, 2017, the Company has adjusted the System Restoration Charge implemented after Hurricane Katrina to zero. Upon completion of the proper defeasance process by the Mississippi State Bond Commission, the Company's obligations in relation to system restoration bonds issued after Hurricane Katrina in 2005 will be completely satisfied.

Provision for Property Damage

On January 21, 2017, a tornado caused extensive damage to the Company's transmission and distribution infrastructure. Preliminary storm damage repairs have been estimated at $11 million . A portion of these costs may be charged to the retail property damage reserve and addressed in a subsequent SRR rate filing. The ultimate outcome of this matter cannot be determined at this time.

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

The Kemper IGCC utilizes IGCC technology with an expected output capacity of 582 MWs. The Kemper IGCC is fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation in 2013. In connection with the Kemper IGCC, the Company constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the transport of captured CO_2 for use in enhanced oil recovery.

Kemper IGCC Schedule and Cost Estimate

In 2012, the Mississippi PSC issued the 2012 MPSC CPCN Order, a detailed order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC . The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC CPCN Order was $2.4 billion , net of $245 million of Initial DOE Grants and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and AFUDC related to the Kemper IGCC. The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion , with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. The Kemper IGCC was originally projected to be placed in service in May 2014. The Company placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service in August 2014. The remainder of the plant, including the gasifiers and the gas clean-up facilities, represents first-of-a-kind technology. The initial production of syngas began on July 14, 2016 for gasifier "B" and on September 13, 2016 for gasifier "A." The Company achieved integrated operation of both gasifiers on January 29, 2017, including the production of electricity from syngas in both combustion turbines. The Company subsequently completed a brief outage to repair and make modifications to further improve the plant's ability to achieve sustained operations sufficient to support placing the plant in service for customers. Efforts to reach sustained operation of both gasifiers and production of electricity from syngas in both combustion turbines are in process. The plant has produced and captured CO_2 , and has produced sulfuric acid and ammonia, all of acceptable quality under the related off-take agreements. On February 20, 2017, the Company determined gasifier "B," which has been producing syngas over 60% of the time since early November 2016, requires an outage to remove ash deposits from its ash removal system. Gasifier "A" and combustion turbine "A" are expected to remain in operation, producing electricity from syngas, as well as producing chemical by-products. As a result, the Company currently expects the remainder of the Kemper IGCC, including both gasifiers, will be placed in service by mid-March 2017.

The Company's Kemper IGCC 2010 project estimate, current cost estimate (which includes the impacts of the Mississippi Supreme Court's (Court) decision discussed herein under "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order"), and actual costs incurred as of December 31, 2016, all of which include 100% of the costs for the Kemper IGCC, are as follows:

Cost Category	2010 Project Estimate [(a)]	Current Cost Estimate [(b)]	**Actual Costs**
		(in billions)	
Plant Subject to Cost Cap [(c)(e)]	$ 2.40	$ 5.64	**$ 5.44**
Lignite Mine and Equipment	0.21	0.23	**0.23**
CO_2 Pipeline Facilities	0.14	0.11	**0.11**
AFUDC [(d)]	0.17	0.79	**0.75**
Combined Cycle and Related Assets Placed in Service – Incremental [(e)]	—	0.04	**0.04**
General Exceptions	0.05	0.10	**0.09**
Deferred Costs [(e)]	—	0.22	**0.21**
Additional DOE Grants	—	(0.14)	**(0.14)**
Total Kemper IGCC [(f)]	$ 2.97	$ 6.99	**$ 6.73**

(a) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities approved in 2011 by the Mississippi PSC, as well as the lignite mine and equipment, AFUDC, and general exceptions.

(b) Amounts in the Current Cost Estimate include certain estimated post-in-service costs which are expected to be subject to the cost cap.

(c) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion , net of the Initial DOE Grants and excluding the Cost Cap Exceptions. The Current Cost Estimate and the Actual Costs include non-incremental operating and maintenance costs related to the combined cycle and associated

common facilities placed in service in August 2014 that are subject to the $2.88 billion cost cap and exclude post-in-service costs for the lignite mine. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" herein for additional information.

(d) The Company's 2010 Project Estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC as described in "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order." The Current Cost Estimate also reflects the impact of a settlement agreement with the wholesale customers for cost-based rates under FERC's jurisdiction. See "FERC Matters" herein for additional information.

(e) Non-capital Kemper IGCC-related costs incurred during construction were initially deferred as regulatory assets. Some of these costs are now included in rates and are being recognized through income; however, such costs continue to be included in the Current Cost Estimate and the Actual Costs at December 31, 2016. The wholesale portion of debt carrying costs, whether deferred or recognized through income, is not included in the Current Cost Estimate and the Actual Costs at December 31, 2016. See "Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities" herein for additional information.

(f) The Current Cost Estimate and the Actual Costs include $2.76 billion that will not be recovered for costs above the cost cap, $0.83 billion of investment costs included in current rates for the combined cycle and related assets in service, and $0.08 billion of costs that were previously expensed for the combined cycle and related assets in service. The Current Cost Estimate and the Actual Costs exclude $0.25 billion of costs not included in current rates for post-June 2013 mine operations, the lignite fuel inventory, and the nitrogen plant capital lease, which will be included in the 2017 Rate Case to be filed by June 3, 2017. See Note 1 to the financial statements under "Fuel Inventory," Note 6 to the financial statements under "Capital Leases," and "Rate Recovery of Kemper IGCC Costs – 2017 Rate Case" herein for additional information.

Of the total costs, including post-in-service costs for the lignite mine, incurred as of December 31, 2016 , $3.67 billion was included in property, plant, and equipment (which is net of the Initial DOE Grants, the Additional DOE Grants, and estimated probable losses of $2.84 billion), $6 million in other property and investments, $75 million in fossil fuel stock, $47 million in materials and supplies, $29 million in other regulatory assets, current, $172 million in other regulatory assets, deferred, $3 million in other current assets, and $14 million in other deferred charges and assets in the balance sheet.

The Company does not intend to seek rate recovery for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. The Company recorded pre-tax charges to income for revisions to the cost estimate of $348 million ($215 million after tax), $365 million ($226 million after tax), and $868 million ($536 million after tax) in 2016, 2015, and 2014, respectively. Since 2012, in the aggregate, the Company has incurred charges of $2.76 billion ($1.71 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2016. The increases to the cost estimate in 2016 primarily reflect $186 million for the extension of the Kemper IGCC's projected in-service date from August 31, 2016 to March 15, 2017 and $162 million for increased efforts related to operational readiness and challenges in start-up and commissioning activities, including the cost of repairs and modifications to both gasifiers, mechanical improvements to coal feed and ash management systems, and outage work, as well as certain post-in-service costs expected to be subject to the cost cap.

In addition to the current construction cost estimate, the Company is identifying potential improvement projects that ultimately may be completed subsequent to placing the remainder of the Kemper IGCC in service. If completed, such improvement projects would be expected to enhance plant performance, safety, and/or operations. As of December 31, 2016, approximately $12 million of related potential costs has been included in the estimated loss on the Kemper IGCC. Other projects have yet to be fully evaluated, have not been included in the current cost estimate, and may be subject to the $2.88 billion cost cap.

Any extension of the in-service date beyond mid-March 2017 is currently estimated to result in additional base costs of approximately $25 million to $35 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. Additional costs may be required for remediation of any further equipment and/or design issues identified. Any extension of the in-service date with respect to the Kemper IGCC beyond mid-March 2017 would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $16 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees of approximately $3 million per month. For additional information, see "2015 Rate Case" herein.

Further cost increases and/or extensions of the expected in-service date may result from factors including, but not limited to, difficulties integrating the systems required for sustained operations, sustaining nitrogen supply, major equipment failure, unforeseen engineering or design problems including any repairs and/or modifications to systems, and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC). Any further changes in the estimated costs of the Kemper IGCC subject to the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the Company's statements of income and these changes could be material.

Rate Recovery of Kemper IGCC Costs

Given the variety of potential scenarios and the uncertainty of the outcome of future regulatory proceedings with the Mississippi PSC (and any subsequent related legal challenges), the ultimate outcome of the rate recovery matters discussed herein, including

the resolution of legal challenges, cannot now be determined but could result in further material charges that could have a material impact on the Company's results of operations, financial condition, and liquidity.

As of December 31, 2016, in addition to the $2.76 billion of costs above the Mississippi PSC's $2.88 billion cost cap that have been recognized as a charge to income, the Company had incurred approximately $1.99 billion in costs subject to the cost cap and approximately $1.46 billion in Cost Cap Exceptions related to the construction and start-up of the Kemper IGCC that are not included in current rates. These costs primarily relate to the following:

Cost Category		Actual Costs
		(in billions)
Gasifiers and Gas Clean-up Facilities	$	1.88
Lignite Mine Facility		0.31
CO_2 Pipeline Facilities		0.11
Combined Cycle and Common Facilities		0.16
AFUDC		0.69
General exceptions		0.07
Plant inventory		0.03
Lignite inventory		0.08
Regulatory and other deferred assets		0.12
Subtotal	$	3.45
Additional DOE Grants		(0.14)
Total	**$**	**3.31**

Of these amounts, approximately 29% is related to wholesale and approximately 71% is related to retail, including the 15% portion that was previously contracted to be sold to SMEPA. The Company and its wholesale customers have generally agreed to the similar regulatory treatment for wholesale tariff purposes as approved by the Mississippi PSC for retail for Kemper IGCC-related costs. See "FERC Matters – Municipal and Rural Associations Tariff" and "Termination of Proposed Sale of Undivided Interest" herein for further information.

Prudence

On August 17, 2016, the Mississippi PSC issued an order establishing a discovery docket to manage all filings related to the prudence of the Kemper IGCC. On October 3, 2016, the Company made a required compliance filing, which included a review and explanation of differences between the Kemper IGCC project estimate set forth in the 2010 CPCN proceedings and the most recent Kemper IGCC project estimate, as well as comparisons of current cost estimates and current expected plant operational parameters to the estimates presented in the 2010 CPCN proceedings for the first five years after the Kemper IGCC is placed in service. Compared to amounts presented in the 2010 CPCN proceedings, operations and maintenance expenses have increased an average of $105 million annually and maintenance capital has increased an average of $44 million annually for the first full five years of operations for the Kemper IGCC. Additionally, while the current estimated operational availability estimates reflect ultimate results similar to those presented in the 2010 CPCN proceedings, the ramp up period for the current estimates reflects a lower starting point and a slower escalation rate. On November 17, 2016, the Company submitted a supplemental filing to the October 3, 2016 compliance filing to present revised non-fuel operations and maintenance expense projections for the first year after the Kemper IGCC is placed in service. This supplemental filing included approximately $68 million in additional estimated operations and maintenance costs expected to be required to support the operations of the Kemper IGCC during that period. The Company will not seek recovery of the $68 million in additional estimated costs from customers if incurred.

The Company expects the Mississippi PSC to address these matters in connection with the 2017 Rate Case.

Economic Viability Analysis

In the fourth quarter 2016, as a part of its Integrated Resource Plan process, the Southern Company system completed its regular annual updated fuel forecast, the 2017 Annual Fuel Forecast. This updated fuel forecast reflected significantly lower long-term estimated costs for natural gas than were previously projected.

As a result of the updated long-term natural gas forecast, as well as the revised operating expense projections reflected in the discovery docket filings discussed above, on February 21, 2017, the Company filed an updated project economic viability

analysis of the Kemper IGCC as required under the 2012 MPSC CPCN Order confirming authorization of the Kemper IGCC. The project economic viability analysis measures the life cycle economics of the Kemper IGCC compared to feasible alternatives, natural gas combined cycle generating units, under a variety of scenarios and considering fuel, operating and capital costs, and operating characteristics, as well as federal and state taxes and incentives. The reduction in the projected long-term natural gas prices in the 2017 Annual Fuel Forecast and, to a lesser extent, the increase in the estimated Kemper IGCC operating costs, negatively impact the updated project economic viability analysis.

The Company expects the Mississippi PSC to address this matter in connection with the 2017 Rate Case.

2017 Accounting Order Request

After the remainder of the plant is placed in service, AFUDC equity of approximately $11 million per month will no longer be recorded in income, and the Company expects to incur approximately $25 million per month in depreciation, taxes, operations and maintenance expenses, interest expense, and regulatory costs in excess of current rates. The Company expects to file a request for authority from the Mississippi PSC and the FERC to defer all Kemper IGCC costs incurred after the in-service date that cannot be capitalized, are not included in current rates, and are not required to be charged against earnings as a result of the $2.88 billion cost cap until such time as the Mississippi PSC completes its review and includes the resulting allowable costs in rates. In the event that the Mississippi PSC does not grant the Company's request, these monthly expenses will be charged to income as incurred and will not be recoverable through rates.

2017 Rate Case

The Company continues to believe that all costs related to the Kemper IGCC have been prudently incurred in accordance with the requirements of the 2012 MPSC CPCN Order. The Company also recognizes significant areas of potential challenge during future regulatory proceedings (and any subsequent, related legal challenges) exist. As described further herein and under "Prudence," "Lignite Mine and CO_2 Pipeline Facilities," "Termination of Proposed Sale of Undivided Interest," and "Income Tax Matters," these challenges include, but are not limited to, prudence issues associated with capital costs, financing costs (AFUDC), and future operating costs net of chemical revenues; potential operating parameters; income tax issues; costs deferred as regulatory assets; and the 15% portion of the project previously contracted to SMEPA.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization of up to $1.0 billion of prudently-incurred costs was enacted into law in 2013. The Company expects to utilize this legislation to securitize prudently-incurred qualifying facility costs in excess of the certificated cost estimate of $2.4 billion . Qualifying facility costs include, but are not limited to, pre-construction costs, construction costs, regulatory costs, and accrued AFUDC. The Court's decision regarding the 2013 MPSC Rate Order did not impact the Company's ability to utilize alternate financing through securitization or the February 2013 legislation.

Although the 2017 Rate Case has not yet been filed and is subject to future developments with either the Kemper IGCC or the Mississippi PSC, consistent with its approach in the 2013 and 2015 rate proceedings in accordance with the law passed in 2013 authorizing multi-year rate plans, the Company is developing both a traditional rate case requesting full cost recovery of the amounts not currently in rates and a rate mitigation plan that together represent the Company's probable filing strategy. The Company also expects that timely resolution of the 2017 Rate Case will likely require a negotiated settlement agreement. In the event an agreement acceptable to both the Company and the MPUS (and other parties) can be negotiated and ultimately approved by the Mississippi PSC, it is reasonably possible that full regulatory recovery of all Kemper IGCC costs will not occur. The impact of such an agreement on the Company's financial statements would depend on the method, amount, and type of cost recovery ultimately excluded. Certain costs, including operating costs, would be recorded to income in the period incurred, while other costs, including investment-related costs, would be charged to income when it is probable they will not be recovered and the amounts can be reasonably estimated. In the event an agreement acceptable to the parties cannot be reached, the Company intends to fully litigate its request for full recovery through the Mississippi PSC regulatory process and any subsequent legal challenges.

The Company has evaluated various scenarios in connection with its processes to prepare the 2017 Rate Case and has recognized an additional $80 million charge to income, which is the estimated minimum probable amount of the $3.31 billion of Kemper IGCC costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017.

2015 Rate Case

On August 13, 2015, the Mississippi PSC approved the Company's request for interim rates, which presented an alternative rate proposal (In-Service Asset Proposal) designed to recover the Company's costs associated with the Kemper IGCC assets that are commercially operational and currently providing service to customers (the transmission facilities, combined cycle, natural gas

pipeline, and water pipeline) and other related costs. The interim rates were designed to collect approximately $159 million annually and became effective in September 2015, subject to refund and certain other conditions.

On December 3, 2015, the Mississippi PSC issued the In-Service Asset Rate Order adopting in full the 2015 Stipulation entered into between the Company and the MPUS regarding the In-Service Asset Proposal. The In-Service Asset Rate Order provided for retail rate recovery of an annual revenue requirement of approximately $126 million , based on the Company's actual average capital structure, with a maximum common equity percentage of 49.733%, a 9.225% return on common equity, and actual embedded interest costs. The In-Service Asset Rate Order also included a prudence finding of all costs in the stipulated revenue requirement calculation for the in-service assets. The stipulated revenue requirement excluded the costs of the Kemper IGCC related to the 15% undivided interest that was previously projected to be purchased by SMEPA but reserved the Company's right to seek recovery in a future proceeding. See "Termination of Proposed Sale of Undivided Interest" herein for additional information. The Company is required to file the 2017 Rate Case by June 3, 2017.

With implementation of the new rates on December 17, 2015, the interim rates were terminated and, in March 2016, the Company completed customer refunds of approximately $11 million for the difference between the interim rates collected and the permanent rates.

2013 MPSC Rate Order

In January 2013, the Company entered into a settlement agreement with the Mississippi PSC that was intended to establish the process for resolving matters regarding cost recovery related to the Kemper IGCC (2013 Settlement Agreement). Under the 2013 Settlement Agreement, the Company agreed to limit the portion of prudently-incurred Kemper IGCC costs to be included in retail rate base to the $2.4 billion certificated cost estimate, plus the Cost Cap Exceptions, but excluding AFUDC, and any other costs permitted or determined to be excluded from the $2.88 billion cost cap by the Mississippi PSC. In March 2013, the Mississippi PSC issued a rate order approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014 (2013 MPSC Rate Order) to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service, based on a mirror CWIP methodology (Mirror CWIP rate).

On February 12, 2015, the Court reversed the 2013 MPSC Rate Order based on, among other things, its findings that (1) the Mirror CWIP rate treatment was not provided for under the Baseload Act and (2) the Mississippi PSC should have determined the prudence of Kemper IGCC costs before approving rate recovery through the 2013 MPSC Rate Order. The Court also found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. On July 7, 2015, the Mississippi PSC ordered that the Mirror CWIP rate be terminated effective July 20, 2015 and required the fourth quarter 2015 refund of the $342 million collected under the 2013 MPSC Rate Order, along with associated carrying costs of $29 million . The Court's decision did not impact the 2012 MPSC CPCN Order or the February 2013 legislation described above.

Because the 2013 MPSC Rate Order did not provide for the inclusion of CWIP in rate base as permitted by the Baseload Act, the Company continues to record AFUDC on the Kemper IGCC. Through December 31, 2016, AFUDC recorded since the original May 2014 estimated in-service date for the Kemper IGCC has totaled $398 million, which will continue to accrue at approximately $16 million per month until the remainder of the plant is placed in service. The Company has not recorded any AFUDC on Kemper IGCC costs in excess of the $2.88 billion cost cap, except for Cost Cap Exception amounts.

2012 MPSC CPCN Order

The 2012 MPSC CPCN Order included provisions relating to both the Company's recovery of financing costs during the course of construction of the Kemper IGCC and the Company's recovery of costs following the date the Kemper IGCC is placed in service. With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC CPCN Order provided for the establishment of operational cost and revenue parameters including availability factor, heat rate, lignite heat content, and chemical revenue based upon assumptions in the Company's petition for the CPCN. The Company expects the Mississippi PSC to apply operational parameters in connection with the 2017 Rate Case and future proceedings related to the operation of the Kemper IGCC. To the extent the Mississippi PSC determines the Kemper IGCC does not meet the operational parameters ultimately adopted by the Mississippi PSC or the Company incurs additional costs to satisfy such parameters, there could be a material adverse impact on the Company's financial statements. See "Prudence" herein for additional information.

Regulatory Assets and Liabilities

Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC issued an accounting order in 2011 granting the Company the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset through the in-service date, subject to review of such costs by the Mississippi PSC. Such costs include, but are not limited

to, carrying costs on Kemper IGCC assets currently placed in service, costs associated with Mississippi PSC and MPUS consultants, prudence costs, legal fees, and operating expenses associated with assets placed in service.

In August 2014, the Company requested confirmation by the Mississippi PSC of the Company's authority to defer all operating expenses associated with the operation of the combined cycle subject to review of such costs by the Mississippi PSC. In addition, the Company is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings. Beginning in the third quarter 2015 and the second quarter 2016, in connection with the implementation of retail and wholesale rates, respectively, the Company began expensing certain ongoing project costs and certain retail debt carrying costs (associated with assets placed in service and other non-CWIP accounts) that previously were deferred as regulatory assets and began amortizing certain regulatory assets associated with assets placed in service and consulting and legal fees. The amortization periods for these regulatory assets vary from two years to 10 years as set forth in the In-Service Asset Rate Order and the settlement agreement with wholesale customers. As of December 31, 2016, the balance associated with these regulatory assets was $97 million , of which $29 million is included in current assets. Other regulatory assets associated with the remainder of the Kemper IGCC totaled $104 million as of December 31, 2016 . The amortization period for these assets is expected to be determined by the Mississippi PSC in the 2017 Rate Case. See "FERC Matters" herein for additional information related to the 2016 settlement agreement with wholesale customers.

The In-Service Asset Rate Order requires the Company to submit an annual true-up calculation of its actual cost of capital, compared to the stipulated total cost of capital, with the first occurring as of May 31, 2016. At December 31, 2016, the Company's related regulatory liability included in its balance sheet totaled approximately $7 million . See "2015 Rate Case" herein for additional information.

Also see Note 1 to the financial statements under "Regulatory Assets and Liabilities" for additional information.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, the Company owns the lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site. The mine started commercial operation in June 2013.

In 2010, the Company executed a 40 -year management fee contract with Liberty Fuels Company, LLC (Liberty Fuels), a wholly-owned subsidiary of The North American Coal Corporation, which developed, constructed, and is operating and managing the mining operations. The contract with Liberty Fuels is effective through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and the Company has a contractual obligation to fund all reclamation activities. In addition to the obligation to fund the reclamation activities, the Company currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" and "Variable Interest Entities" for additional information.

In addition, the Company has constructed and will operate the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. The Company entered into agreements with Denbury Onshore (Denbury) and Treetop Midstream Services, LLC (Treetop), pursuant to which Denbury would purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop would purchase 30% of the CO_2 captured from the Kemper IGCC. On June 3, 2016, the Company cancelled its contract with Treetop and amended its contract with Denbury to reflect, among other things, Denbury's agreement to purchase 100% of the CO_2 captured from the Kemper IGCC, an initial contract term of 16 years, and termination rights if the Company has not satisfied its contractual obligation to deliver captured CO_2 by July 1, 2017, in addition to Denbury's existing termination rights in the event of a change in law, force majeure, or an event of default by the Company. Any termination or material modification of the agreement with Denbury could impact the operations of the Kemper IGCC and result in a material reduction in the Company's revenues to the extent the Company is not able to enter into other similar contractual arrangements or otherwise sequester the CO_2 produced. Additionally, sustained oil price reductions could result in significantly lower revenues than the Company originally forecasted to be available to offset customer rate impacts, which could have a material impact on the Company's financial statements.

The ultimate outcome of these matters cannot be determined at this time.

Termination of Proposed Sale of Undivided Interest

In 2010 and as amended in 2012, the Company and SMEPA entered into an agreement whereby SMEPA agreed to purchase a 15% undivided interest in the Kemper IGCC (15% Undivided Interest). On May 20, 2015, SMEPA notified the Company of its termination of the agreement. The Company previously received a total of $275 million of deposits from SMEPA that were required to be returned to SMEPA with interest. On June 3, 2015, Southern Company, pursuant to its guarantee obligation,

returned approximately $301 million to SMEPA. Subsequently, the Company issued a promissory note in the aggregate principal amount of approximately $301 million to Southern Company, which matures on December 1, 2017.

Litigation

On April 26, 2016, a complaint against the Company was filed in Harrison County Circuit Court (Circuit Court) by Biloxi Freezing & Processing Inc., Gulfside Casino Partnership, and John Carlton Dean, which was amended and refiled on July 11, 2016 to include, among other things, Southern Company as a defendant. On August 12, 2016, Southern Company and the Company removed the case to the U.S. District Court for the Southern District of Mississippi. The plaintiffs filed a request to remand the case back to state court, which was granted on November 17, 2016. The individual plaintiff, John Carlton Dean, alleges that the Company and Southern Company violated the Mississippi Unfair Trade Practices Act. All plaintiffs have alleged that the Company and Southern Company concealed, falsely represented, and failed to fully disclose important facts concerning the cost and schedule of the Kemper IGCC and that these alleged breaches have unjustly enriched the Company and Southern Company. The plaintiffs seek unspecified actual damages and punitive damages; ask the Circuit Court to appoint a receiver to oversee, operate, manage, and otherwise control all affairs relating to the Kemper IGCC; ask the Circuit Court to revoke any licenses or certificates authorizing the Company or Southern Company to engage in any business related to the Kemper IGCC in Mississippi; and seek attorney's fees, costs, and interest. The plaintiffs also seek an injunction to prevent any Kemper IGCC costs from being charged to customers through electric rates. On December 7, 2016, Southern Company and the Company filed motions to dismiss.

On June 9, 2016, Treetop, Greenleaf, Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group filed a complaint against the Company, Southern Company, and SCS in the state court in Gwinnett County, Georgia. The complaint relates to the cancelled CO_2 contract with Treetop and alleges fraudulent misrepresentation, fraudulent concealment, civil conspiracy, and breach of contract on the part of the Company, Southern Company, and SCS and seeks compensatory damages of $100 million , as well as unspecified punitive damages. Southern Company, the Company, and SCS have moved to compel arbitration pursuant to the terms of the CO_2 contract.

The Company believes these legal challenges have no merit; however, an adverse outcome in these proceedings could have a material impact on the Company's results of operations, financial condition, and liquidity. The Company will vigorously defend itself in these matters, and the ultimate outcome of these matters cannot be determined at this time.

Baseload Act

In 2008, the Baseload Act was signed by the Governor of Mississippi. The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently-incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. See "Rate Recovery of Kemper IGCC Costs" herein for additional information.

Income Tax Matters

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information about the Kemper IGCC.

Bonus Depreciation

In December 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service through 2020. The PATH Act allows for 50% bonus depreciation for 2015 through 2017, 40% bonus depreciation for 2018, and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. The extension of bonus depreciation included in the PATH Act is expected to result in approximately $20 million of positive cash flows for the 2016 tax year, which was not all realized in 2016 due to a projected consolidated net operating loss (NOL) for Southern Company. Dependent upon placing the remainder of the Kemper IGCC in service by December 31, 2017, the Company expects approximately $370 million of positive cash flows from bonus depreciation for the 2017 tax year, which may not all be realized in 2017 due to additional NOL projections for the 2017 tax year. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" and Note 5 to the financial statements under "Current and Deferred Income Taxes – Net Operating Loss" for additional information. The ultimate outcome of this matter cannot be determined at this time.

Investment Tax Credits

The IRS allocated $133 million (Phase I) and $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to the Company in connection with the Kemper IGCC. These tax credits were dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In addition, the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the Internal Revenue Code was also a requirement of the Phase II credits. As a result of schedule extensions for the Kemper IGCC, the Phase I tax credits were recaptured in 2013 and the Phase II tax credits were recaptured in 2015.

Section 174 Research and Experimental Deduction

Southern Company, on behalf of the Company, has reflected deductions for research and experimental (R&E) expenditures related to the Kemper IGCC in its federal income tax calculations since 2013 and has filed amended federal income tax returns for 2008 through 2013 to also include such deductions. The Kemper IGCC is based on first-of-a-kind technology, and Southern Company believes that a significant portion of the plant costs qualify as deductible R&E expenditures under Internal Revenue Code Section 174. In December 2016, Southern Company and the IRS reached a proposed settlement, subject to approval of the U.S. Congress Joint Committee on Taxation, resolving a methodology for these deductions. Due to the uncertainty related to this tax position, the Company had unrecognized tax benefits associated with these R&E deductions totaling approximately $464 million as of December 31, 2016 . See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information. This matter is expected to be resolved in the next 12 months; however, the ultimate outcome of this matter cannot be determined at this time.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

In 2013, the Company submitted a claim under the Deepwater Horizon Economic and Property Damages Settlement Agreement associated with the oil spill that occurred in 2010 in the Gulf of Mexico. The ultimate outcome of this matter cannot be determined at this time.

The SEC is conducting a formal investigation of Southern Company and the Company concerning the estimated costs and expected in-service date of the Kemper IGCC. Southern Company and the Company believe the investigation is focused primarily on periods subsequent to 2010 and on accounting matters, disclosure controls and procedures, and internal controls over financial reporting associated with the Kemper IGCC. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" herein for additional information on the Kemper IGCC estimated construction costs and expected in-service date. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to have a material impact on the Company's financial statements.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that

are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Utility Regulation

The Company is subject to retail regulation by the Mississippi PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and other postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Kemper IGCC Estimated Construction Costs, Project Completion Date, and Rate Recovery

During 2016 , the Company further revised its cost estimate to complete construction and start-up of the Kemper IGCC to an amount that exceeds the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. The Company does not intend to seek any rate recovery for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions.

As a result of revisions to the cost estimate, the Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC subject to the construction cost cap of $127 million ($78 million after tax) in the fourth quarter 2016, $88 million ($54 million after tax) in the third quarter 2016, $81 million ($50 million after tax) in the second quarter 2016, $53 million ($33 million after tax) in the first quarter 2016, $183 million ($113 million after tax) in the fourth quarter 2015, $150 million ($93 million after tax) in the third quarter 2015, $23 million ($14 million after tax) in the second quarter 2015, $9 million ($6 million after tax) in the first quarter 2015, $70 million ($43 million after tax) in the fourth quarter 2014, $418 million ($258 million after tax) in the third quarter 2014, $380 million ($235 million after tax) in the first quarter 2014, $40 million ($25 million after tax) in the fourth quarter 2013, $150 million ($93 million after tax) in the third quarter 2013, $450 million ($278 million after tax) in the second quarter 2013, $462 million ($285 million after tax) in the first quarter 2013, and $78 million ($48 million after tax) in the fourth quarter 2012. In the aggregate, the Company has incurred charges of $2.76 billion ($1.71 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2016 .

The Company's revised cost estimate reflects an expected in-service date of mid-March 2017 and includes certain post-in-service costs which are expected to be subject to the cost cap. The Company has experienced, and may continue to experience, material changes in the cost estimate for the Kemper IGCC. Further cost increases and/or extensions of the expected in-service date may result from factors including, but not limited to, difficulties integrating the systems required for sustained operations, sustaining nitrogen supply, major equipment failure, unforeseen engineering or design problems including any repairs and/or modifications to systems, and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC).

In addition to the current construction cost estimate, the Company is also identifying potential improvement projects that ultimately may be completed subsequent to placing the remainder of the Kemper IGCC in service. If completed, such improvement projects would be expected to enhance plant performance, safety, and/or operations. As of December 31, 2016, approximately $12 million of related potential costs has been included in the estimated loss on the Kemper IGCC. Other projects have yet to be fully evaluated, have not been included in the current cost estimate, and may be subject to the $2.88 billion cost cap. In subsequent periods, any further changes in the estimated costs of the Kemper IGCC subject to the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the statements of income and these changes could be material.

Any extension of the in-service date beyond mid-March 2017 is currently estimated to result in additional base costs of approximately $25 million to $35 million per month, which includes maintaining necessary levels of start-up labor, materials, and

fuel, as well as operational resources required to execute start-up and commissioning activities. However, additional costs may be required for remediation of any further equipment and/or design issues identified. Any extension of the in-service date with respect to the Kemper IGCC beyond mid-March 2017 would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $16 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees of approximately $3 million per month.

The Company continues to believe that all costs related to the Kemper IGCC have been prudently incurred in accordance with the requirements of the 2012 MPSC CPCN Order. The Company also recognizes significant areas of potential challenge during future regulatory proceedings (and any subsequent, related legal challenges) exist. As described further under FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs," " – Prudence," " – Lignite Mine and CO_2 Pipeline Facilities," and " – Termination of Proposed Sale of Undivided Interest" and "Income Tax Matters," these challenges include, but are not limited to, prudence issues associated with capital costs, financing costs (AFUDC), and future operating costs, net of chemical revenues; potential operating parameters; income tax issues; costs deferred as regulatory assets; and the 15% portion of the project previously contracted to SMEPA.

Although the 2017 Rate Case has not yet been filed and is subject to future developments with either the Kemper IGCC or the Mississippi PSC, consistent with its approach in the 2013 and 2015 rate proceedings in accordance with the law passed in 2013 authorizing multi-year rate plans, the Company is developing both a traditional rate case requesting full cost recovery of the amounts not currently in rates and a rate mitigation plan that together represent the Company's probable filing strategy. The Company also expects that timely resolution of the 2017 Rate Case will likely require a negotiated settlement agreement. In the event an agreement acceptable to both the Company and the MPUS (and other parties) can be negotiated and ultimately approved by the Mississippi PSC, it is reasonably possible that full regulatory recovery of all Kemper IGCC costs will not occur. The impact of such an agreement on the Company's financial statements would depend on the method, amount, and type of cost recovery ultimately excluded. Certain costs, including operating costs, would be recorded to income in the period incurred, while other costs, including investment-related costs, would be charged to income when it is probable they will not be recovered and the amounts can be reasonably estimated. In the event an agreement acceptable to the parties cannot be reached, the Company intends to fully litigate its request for full recovery through the Mississippi PSC regulatory process and any subsequent legal challenges.

The Company has evaluated various scenarios in connection with its processes to prepare the 2017 Rate Case and has recognized an additional $80 million charge to income, which is the estimated minimum probable amount of the $3.31 billion of Kemper IGCC costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017.

Given the significant judgment involved in estimating the future costs to complete construction and start-up, the project completion date, the ultimate rate recovery for the Kemper IGCC, and the potential impact on results of operations, the Company considers these items to be critical accounting estimates. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

Asset Retirement Obligations

AROs are computed as the fair value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities.

The liability for AROs primarily relates to facilities that are subject to the CCR Rule, principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, deep injection wells, water wells, substation removal, mine reclamation, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO.

The cost estimates for AROs related to the disposal of CCR are based on information using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing with respect to compliance activities, including the potential for closing ash ponds prior to the end of their

currently anticipated useful life, the Company expects to continue to periodically update these estimates. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Coal Combustion Residuals" herein for additional information.

Given the significant judgment involved in estimating AROs, the Company considers the liabilities for AROs to be critical accounting estimates.

See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, the Company discounts the future related cash flows using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. For 2015 and prior years, the Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. For 2016, the Company adopted a full yield curve approach for calculating the interest cost component whereby the discount rate for each year is applied to the liability for that specific year. As a result, the interest cost component of net periodic pension and other postretirement benefit plan expense decreased by approximately $4 million in 2016.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $2 million or less change in total annual benefit expense and a $19 million or less change in projected obligations.

See Note 2 to the financial statements for additional information regarding pension and other postretirement benefits.

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in the calculation of taxable income. The average annual AFUDC rate was 6.5% , 5.99% , and 6.91% for the years ended December 31, 2016 , 2015 , and 2014 , respectively. The AFUDC rate is applied to CWIP consistent with jurisdictional regulatory treatment. AFUDC equity was $124 million , $110 million, and $136 million in 2016, 2015, and 2014, respectively.

Unbilled Revenues

Revenues related to the retail sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations as well as other factors and conditions that subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's results of operations, cash flows, or financial condition.

Recently Issued Accounting Standards

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers,* replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

While the Company expects most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of such arrangements. The majority of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term. For such arrangements, the Company generally expects that the revenue from contracts with these customers will continue to be equivalent to the electricity supplied and billed in that period (including unbilled revenues) and the adoption of ASC 606 will not result in a significant shift in the timing of revenue recognition for such sales.

The Company's ongoing evaluation of other revenue streams and related contracts includes longer term contractual commitments and unregulated sales to customers. Some revenue arrangements, such as certain PPAs and alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on the Company's financial statements. In addition, the power and utilities industry is currently addressing other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). If final implementation guidance indicates CIAC will be accounted for under ASC 606 and offsetting regulatory treatment is not permitted, it could have a material impact on the Company's financial statements.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. The Company must select a transition method to be applied either retrospectively to each prior reporting period presented or retrospectively with a cumulative effect adjustment to retained earnings at the date of initial adoption. As the ultimate impact of the new standard has not yet been determined, the Company has not elected its transition method.

On February 25, 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged . ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company is currently evaluating the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

On March 30, 2016, the FASB issued ASU No. 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5, 8, and 11 to the financial statements for disclosures impacted by ASU 2016-09.

On October 24, 2016, the FASB issued ASU No. 2016-16, *Income Taxes (Topic 740), Intra-Entity Transfers of Assets Other Than Inventory* (ASU 2016-16). Current GAAP prohibits the recognition of current and deferred income taxes for an affiliate asset transfer until the asset has been sold to an outside party. ASU 2016-16 requires an entity to recognize the income tax consequences of an affiliate transfer of an asset other than inventory when the transfer occurs. ASU 2016-16 is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. The amendments will be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The Company is currently assessing the impact of the standard on its financial statements and has not yet determined its ultimate impact.

In 2014, the FASB issued ASU No. 2014-15, *Presentation of Financial Statements-Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern* (ASU 2014-15). ASU 2014-15 defines management's responsibility to evaluate whether there is substantial doubt about an organization's ability to continue as a going concern within one year of the date the financial statements are issued and to provide related footnote disclosures including management's plans that alleviate substantial doubt. ASU 2014-15 became effective for fiscal years ending after December 15, 2016 and the Company has included the disclosures required by ASU 2014-15 in Note 6 to the financial statements under "Going Concern."

FINANCIAL CONDITION AND LIQUIDITY

Overview

Earnings for all periods presented were negatively affected by revisions to the cost estimate for the Kemper IGCC. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" herein for additional information.

The Company's capital expenditures and debt maturities are expected to materially exceed operating cash flows through 2021. In addition to the Kemper IGCC, projected capital expenditures in that period include investments to maintain existing generation facilities, to add environmental modifications to existing generating units, and to expand and improve transmission and distribution facilities.

As of December 31, 2016, the Company's current liabilities exceeded current assets by approximately $371 million primarily due to $551 million in promissory notes to Southern Company which mature in December 2017, $35 million in senior notes which mature in November 2017, and $63 million in short-term debt. The Company expects the funds needed to satisfy the promissory notes to Southern Company will exceed amounts available from operating cash flows, lines of credit, and other external sources. Accordingly, the Company intends to satisfy these obligations through loans and/or equity contributions from Southern Company. Specifically, the Company has been informed by Southern Company that, in the event sufficient funds are not available from external sources, Southern Company intends to (i) extend the maturity of the $551 million in promissory notes and (ii) provide Mississippi Power with loans and/or equity contributions sufficient to fund the remaining indebtedness scheduled to mature and other cash needs over the next 12 months. Therefore, the Company's financial statement presentation contemplates continuation of the Company as a going concern as a result of Southern Company's anticipated ongoing financial support of the Company, consistent with the requirements of ASU 2014-15. See Note 1 to the financial statements under "Recently Issued Accounting Standards" for additional information regarding ASU 2014-15.

The Company's investments in the qualified pension plan increased in value as of December 31, 2016 as compared to December 31, 2015. On December 19, 2016, the Company voluntarily contributed $47 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated during 2017.

Net cash provided from operating activities totaled $229 million for 2016, an increase of $56 million as compared to 2015. The increase in cash provided from operating activities in 2016 was primarily due to repayment in 2015 of ITCs relating to the Kemper IGCC, as well as the 2015 mirror CWIP refund, partially offset by lower income tax benefits related to the Kemper IGCC in 2016 and lower fuel rates in 2016. Net cash provided from operating activities totaled $173 million for 2015, a decrease of $562 million as compared to 2014. The decrease in net cash provided from operating activities was primarily due to lower R&E tax deductions and lower incremental benefit of ITCs relating to the Kemper IGCC reducing income tax refunds, as well as a decrease in the Mirror CWIP regulatory liability due to the Mirror CWIP refund, partially offset by increases in over recovered regulatory clause revenues and customer liability associated with the Mirror CWIP refund.

Net cash used for investing activities in 2016, 2015, and 2014 totaled $697 million , $906 million , and $1.3 billion , respectively. The cash used for investing activities in 2016 was primarily due to gross property additions related to the Kemper IGCC, partially offset by the receipt of Additional DOE Grants. The cash used for investing activities in 2015 and 2014 was primarily due to gross property additions related to the Kemper IGCC and the Plant Daniel scrubber project.

Net cash provided from financing activities totaled $594 million in 2016 primarily due to long-term debt financings and capital contributions from Southern Company, partially offset by a decrease in short-term borrowings and redemptions of long-term debt.

Net cash provided from financing activities totaled $698 million in 2015 primarily due to short-term borrowings, capital contributions from Southern Company, and long-term debt financings, partially offset by redemptions of long-term debt. Net cash provided from financing activities totaled $593 million in 2014 primarily due to capital contributions from Southern Company, long-term debt financings, and the receipts of interest bearing refundable deposits previously pending, partially offset by redemptions of long-term debt.

Significant balance sheet changes as of December 31, 2016 compared to 2015 included an increase in long-term debt of $538 million. A portion of this debt was used to repay securities and notes payable resulting in a $99 million decrease in securities due within one year and a $477 million decrease in notes payable. Additionally, CWIP increased $291 million primarily due to the Kemper IGCC and the required refund of Mirror CWIP collections which reduced the related customer liability by $72 million. Other significant changes include a $383 million increase in accrued income taxes offset by unrecognized tax benefits of $368 million reclassified from long-term to current. Total common stockholder's equity increased $584 million primarily due to the receipt of capital contributions from Southern Company.

The Company's ratio of common equity to total capitalization plus short-term debt was 45.2% and 47.1% at December 31, 2016 and 2015, respectively. See Note 6 to the financial statements for additional information.

Sources of Capital

As discussed above, the Company's financial condition and its ability to obtain funds needed for normal business operations and completion of the construction and start-up of the Kemper IGCC were adversely affected for all periods presented by events relating to the Kemper IGCC. In December 2015, the Mississippi PSC approved the In-Service Asset Rate Order, which among other things, provided for retail rate recovery of an annual revenue requirement of approximately $126 million effective December 17, 2015. The amount, type, and timing of future financings will depend upon regulatory approval, prevailing market conditions, and other factors, which includes resolution of Kemper IGCC cost recovery. See "Capital Requirements and Contractual Obligations" herein and FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" herein for additional information.

As of December 31, 2016, the Company's current liabilities exceeded current assets by approximately $371 million primarily due to $551 million in promissory notes to Southern Company which mature in December 2017, $35 million in senior notes which mature in November 2017, and $63 million in short-term debt. The Company expects the funds needed to satisfy the promissory notes to Southern Company will exceed amounts available from operating cash flows, lines of credit, and other external sources. Accordingly, the Company intends to satisfy these obligations through loans and/or equity contributions from Southern Company. Specifically, the Company has been informed by Southern Company that, in the event sufficient funds are not available from external sources, Southern Company intends to (i) extend the maturity of the $551 million in promissory notes and (ii) provide Mississippi Power with loans and/or equity contributions sufficient to fund the remaining indebtedness scheduled to mature and other cash needs over the next 12 months. Therefore, the Company's financial statement presentation contemplates continuation of the Company as a going concern as a result of Southern Company's anticipated ongoing financial support of the Company, consistent with the requirements of ASU 2014-15. See Note 1 to the financial statements under "Recently Issued Accounting Standards" for additional information regarding ASU 2014-15.

The Company received $245 million of Initial DOE Grants in prior years that were used for the construction of the Kemper IGCC. An additional $25 million of grants from the DOE is expected to be received for commercial operation of the Kemper IGCC. On April 8, 2016, the Company received approximately $137 million in Additional DOE Grants for the Kemper IGCC, which are expected to be used to reduce future rate impacts for customers. In addition, see Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for information regarding legislation related to the securitization of certain costs of the Kemper IGCC.

The issuance of securities by the Company is subject to regulatory approval by the FERC. Additionally, public offerings of securities are required to be registered with the SEC under the Securities Act of 1933, as amended. The amounts of securities authorized by the FERC are continuously monitored and appropriate filings are made to ensure flexibility in raising capital. Any future financing through secured debt would also require approval by the Mississippi PSC.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

At December 31, 2016 , the Company had approximately $224 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2016 were as follows:

Expires			Executable Term Loans		Expires Within One Year	
2017	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)	*(in millions)*		*(in millions)*		*(in millions)*	
$ 173	$ 173	$ 150	$ —	$ 13	$ 13	$ 160

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Most of these bank credit arrangements, as well as the Company's term loan arrangements, contain covenants that limit debt levels and typically contain cross acceleration or cross default provisions to other indebtedness (including guarantee obligations) of the Company. Such cross default provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness or guarantee obligations over a specific threshold. Such cross acceleration provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2016, the Company was in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowing.

Subject to applicable market conditions, the Company expects to renew or replace its bank credit arrangements as needed, prior to expiration. In connection therewith, the Company may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

A portion of the $150 million unused credit arrangements with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2016 was approximately $40 million.

Short-term borrowings are included in notes payable in the balance sheets. The Company had no short-term borrowings in 2014. Details of short-term borrowing for 2015 and 2016 were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (*)		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2016	$ 23	2.6%	$ 112	2.0%	$ 500
December 31, 2015	$ 500	1.4%	$ 372	1.3%	$ 515

(*) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31.

Financing Activities

In addition to any financings that may be necessary to meet capital requirements, contractual obligations, and storm restoration costs, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Bank Term Loan and Senior Notes

In March 2016, the Company entered into an unsecured term loan agreement with a syndicate of financial institutions for an aggregate amount of $1.2 billion. The Company borrowed $900 million in March 2016 under the term loan agreement and the remaining $300 million in October 2016. The Company used the initial proceeds to repay $900 million in maturing bank loans in March 2016 and the remaining $300 million to repay at maturity the Company's Series 2011A 2.35% Senior Notes due October 15, 2016. This loan matures on April 1, 2018 and bears interest based on one-month LIBOR.

This bank loan has covenants that limit debt levels t o 65% of total capitalization, as defined in the agreement. For purposes of this definition, debt excludes the long-term debt payable to affiliated trusts, other hybrid securities, and securitized debt relating to the contemplated securitization of certain costs of the Kemper IGCC. At December 31, 2016 , the Company was in compliance with its debt limit.

In addition, this bank loan contains cross acceleration provisions to other debt (including guarantee obligations) that would be triggered if the Company defaulted on debt above a specified threshold, the payment of which was then accelerated. The Company is currently in compliance with all such covenants.

Parent Company Loans and Equity Contributions

O n January 28, 2016, the Company issued a promissory note for up to $275 million to Southern Company, which matures in December 2017, bearing interest based on one-month LIBOR. During 2016, the Company borrowed $100 million under this promissory note and an additional $100 million under a separate promissory note issued to Southern Company in November 2015.

On June 27, 2016, the Company received a capital contribution from Southern Company of $225 million, the proceeds of which were used to repay to Southern Company a portion of the promissory note issued in November 2015. As of December 31, 2016 , the amount of outstanding promissory notes to Southern Company tot aled $551 million.

Also, on December 14, 2016, the Company received a capital contribution from Southern Company of $400 million, the proceeds of which were used for general corporate purposes.

Other Obligations

In June 2016, the Company renewed a $10 million short-term note, which matures on June 30, 2017, bearing interest based on three-month LIBOR.

In September 2016, the Company entered into interest rate swaps to fix the variable interest rate on $900 million of the term loan entered into in March 2016.

In December 2016, the Company repaid $2.5 million of a $15 million short-term note, reducing the total short-term notes payable to $22.5 million.

Credit Rating Risk

At December 31, 2016 , the Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that have required or could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and/or Baa2 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, energy price risk management, and transmission. At December 31, 2016 , the maximum amount of potential collateral requirements under these contracts at a rating of BBB and/or Baa2 or BBB- and/or Baa3 was not material. The maximum potential collateral requirements at a rating below BBB- and/or Baa3 equaled approximately $243 million.

Included in these amounts are certain agreements that could require collateral in the event that Alabama Power or Georgia Power has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of the Company to access capital markets, and would be likely to impact the cost at which it does so.

On May 12, 2016, Fitch Ratings, Inc. (Fitch) downgraded the senior unsecured long-term debt rating of the Company to BBB+ from A- and revised the ratings outlook from negative to stable.

On January 10, 2017, S&P revised its consolidated credit rating outlook for Southern Company (including the Company) from negative to stable.

On February 6, 2017, Moody's placed the Company on a ratings review for potential downgrade. The Company's current rating for unsecured debt is Baa3.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, foreign currency exchange rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques that include, but are not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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To mitigate future exposure to a change in interest rates, the Company may enter into derivatives that have been designated as hedges. The weighted average interest rate on $891 million of long-term variable interest rate exposure at December 31, 2016 was 2.17%. If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $9 million at January 1, 2017. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The Company continues to manage retail fuel-hedging programs implemented per the guidelines of the Mississippi PSC and wholesale fuel-hedging programs under agreements with wholesale customers. The Company had no material change in market risk exposure for the year ended December 31, 2016 when compared to the year ended December 31, 2015 .

The changes in fair value of energy-related derivative contracts are substantially attributable to both the volume and the price of natural gas. For the years ended December 31, the changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, were as follows:

	2016 Changes	2015 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (47)**	$ (45)
Contracts realized or settled	**29**	33
Current period changes (*)	**11**	(35)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (7)**	$ (47)

(*) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The net hedge volumes of energy-related derivative contracts, all of which are natural gas swaps, for the years ended December 31 were as follows:

	2016	2015
	mmBtu Volume	
	(in millions)	
Total hedge volume	**36**	32

For natural gas hedges, the weighted average swap contract cost above market prices was approximately $0.19 per mmBtu as of December 31, 2016 and $1.49 per mmBtu as of December 31, 2015 . There were no options outstanding as of the reporting periods presented. The costs associated with natural gas hedges are recovered through the Company's ECMs.

At December 31, 2016 and 2015 , substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the ECM clause.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2 of the fair value hierarchy. See Note 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2016 were as follows:

	Fair Value Measurements December 31, 2016		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
		(in millions)	
Level 1	$ —	$ —	$ —
Level 2	(7)	(4)	(3)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (7)	$ (4)	$ (3)

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements.

Capital Requirements and Contractual Obligations

Approximately $586 million will be required through December 31, 2017 to fund maturities of long-term debt, and $23 million will be required to fund maturities of short-term debt. See "Sources of Capital" herein for additional information.

The construction program of the Company is currently estimated to total $517 million for 2017 , $241 million for 2018 , $274 million for 2019 , $305 million for 2020, and $230 million for 2021, which includes completion of the Kemper IGCC and post-in-service costs. Expenditures related to completion of the Kemper IGCC are currently estimated to be $254 million for 2017. These estimated program amounts also include capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these program amounts are $11 million, $5 million, $24 million, $29 million, and $58 million for 2017 , 2018 , 2019 , 2020, and 2021, respectively. These estimated environmental expenditures do not include potential compliance costs that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from existing, new, modified, or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and "– Global Climate Issues" and – "Integrated Coal Gasification Combined Cycle" herein for additional information.

The Company also anticipates costs associated with closure and monitoring of ash ponds in accordance with the CCR Rule, which are reflected in the Company's ARO liabilities. These costs, which could change as the Company continues to refine its assumptions underlying the cost estimates and evaluate the method and timing of compliance activities, are estimated to be $32 million, $11 million, $6 million, $6 million, and $9 million for the years 2017, 2018, 2019, 2020, and 2021, respectively. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in FERC rules and regulations; Mississippi PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital.

In addition, the construction program includes the development and construction of the Kemper IGCC, a first-of-a-kind technology, which may result in revised estimates during construction. The ability to control costs and avoid cost overruns during the development and construction of new facilities is subject to a number of factors, including, but not limited to, changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, sustaining nitrogen supply, contractor or supplier delay, non-performance under construction, operating, or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design

problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC).

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information and further risks related to the estimated schedule and costs and rate recovery for the Kemper IGCC.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred stock dividends, unrecognized tax benefits, pension and other post-retirement benefit plans, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Contractual Obligations

Contractual obligations at December 31, 2016 were as follows:

	2017	2018-2019	2020-2021	After 2021	Total
			(in millions)		
Long-term debt [a] —					
Principal	$ 626	$ 1,325	$ 270	$ 723	$ 2,944
Interest	98	141	100	598	937
Preferred stock dividends [b]	2	3	3	—	8
Financial derivative obligations [c]	6	4	—	—	10
Unrecognized tax benefits [d]	465	—	—	—	465
Operating leases [e]	2	1	1	—	4
Capital leases [f]	7	13	13	76	109
Purchase commitments —					
Capital [g]	480	508	506	—	1,494
Fuel [h]	290	320	184	251	1,045
Long-term service agreements [i]	15	75	48	244	382
Pension and other postretirement benefits plans [j]	7	15	—	—	22
Total	$ 1,998	$ 2,405	$ 1,125	$ 1,892	$ 7,420

(a) All amounts are reflected based on final maturity dates except for amounts related to certain pollution control revenue bonds. Long-term debt principal for 2017 includes $40 million of pollution control revenue bonds that are classified on the balance sheet at December 31, 2016 as short-term since they are variable rate demand obligations that are supported by short-term credit facilities; however, the final maturity date is in 2028. The Company plans to continue, when economically feasible, to retire higher-cost sec urities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2017, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

(b) Preferred stock does not mature; therefore, amounts are provided for the next five years only.

(c) For additional information, see Notes 1 and 10 to the financial statements.

(d) See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(e) See Note 7 to the financial statements for additional information.

(f) Capital lease related to a 20-year nitrogen supply agreement for the Kemper IGCC. See Note 6 to the financial statements for additional information.

(g) The Company provides estimated capital expenditures for a five-year period, including capital expenditures associated with environmental regulations. At December 31, 2016, significant purchase commitments were outstanding in connection with the construction program. These amounts exclude capital expenditures covered under long-term service agreements, which are reflected separately. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

(h) Includes commitments to purchase coal and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2016.

(i) Long-term service agreements include price escalation based on inflation indices.

(j) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2016 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, customer and sales growth, economic conditions, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan and postretirement benefit plans contributions, financing activities, completion of construction projects, filings with state and federal regulatory authorities, impact of the PATH Act, federal income tax benefits, estimated sales and purchases under power sale and purchase agreements, storm damage cost recovery and repairs, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws regulating emissions, discharges, and disposal to air, water, and land , and also changes in tax and other laws and regulations to which the Company is subject, including potential tax reform legislation, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries ;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development , construction, and operation of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor , sustaining nitrogen supply, contractor or supplier delay, non-performance under operating or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC);
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any environmental performance standards and the requirements of tax credits and other incentives , and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of the Company's employee and retiree benefit plans ;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- actions related to cost recovery for the Kemper IGCC, including the ultimate impact of the 2015 decision of the Mississippi Supreme Court, the Mississippi PSC's December 2015 rate order, and related legal or regulatory proceedings, Mississippi PSC review of the prudence of Kemper IGCC costs and approval of further permanent rate recovery plans, actions relating to proposed securitization, satisfaction of requirements to utilize grants, and the ultimate impact of the termination of the proposed sale of an interest in the Kemper IGCC to SMEPA;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;

- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general ;
- the ability of the Company to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2016 , 2015 , and 2014
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	2016	2015	2014
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 859**	$ 776	$ 795
Wholesale revenues, non-affiliates	**261**	270	323
Wholesale revenues, affiliates	**26**	76	107
Other revenues	**17**	16	18
Total operating revenues	**1,163**	1,138	1,243
Operating Expenses:			
Fuel	**343**	443	574
Purchased power, non-affiliates	**5**	5	18
Purchased power, affiliates	**29**	7	25
Other operations and maintenance	**312**	274	271
Depreciation and amortization	**132**	123	97
Taxes other than income taxes	**109**	94	79
Estimated loss on Kemper IGCC	**428**	365	868
Total operating expenses	**1,358**	1,311	1,932
Operating Loss	**(195)**	(173)	(689)
Other Income and (Expense):			
Allowance for equity funds used during construction	**124**	110	136
Interest expense, net of amounts capitalized	**(74)**	(7)	(45)
Other income (expense), net	**(7)**	(8)	(14)
Total other income and (expense)	**43**	95	77
Loss Before Income Taxes	**(152)**	(78)	(612)
Income taxes (benefit)	**(104)**	(72)	(285)
Net Loss	**(48)**	(6)	(327)
Dividends on Preferred Stock	**2**	2	2
Net Loss After Dividends on Preferred Stock	**$ (50)**	$ (8)	$ (329)

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2016 , 2015 , and 2014
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	2016	2015	2014
		(in millions)	
Net Loss	**$ (48)**	$ (6)	$ (327)
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $1, $-, and $-, respectively	**1**	—	—
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $1, respectively	**1**	1	1
Total other comprehensive income (loss)	**2**	1	1
Comprehensive Loss	**$ (46)**	$ (5)	$ (326)

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2016 , 2015 , and 2014
Mississippi Power Company 2016 Annual Report

	2016	2015	2014
		(in millions)	
Operating Activities:			
Net loss	**$ (48)**	$ (6)	$ (327)
Adjustments to reconcile net loss to net cash provided from operating activities —			
Depreciation and amortization, total	**157**	126	104
Deferred income taxes	**(67)**	777	145
Investment tax credits	**—**	(210)	(38)
Allowance for equity funds used during construction	**(124)**	(110)	(136)
Pension and postretirement funding	**(47)**	—	(33)
Regulatory assets associated with Kemper IGCC	**(12)**	(61)	(72)
Estimated loss on Kemper IGCC	**428**	365	868
Income taxes receivable, non-current	**—**	(544)	—
Other, net	**(20)**	8	22
Changes in certain current assets and liabilities —			
-Receivables	**13**	28	(22)
-Prepaid income taxes	**39**	(35)	(50)
-Other current assets	**(8)**	(18)	(6)
-Accounts payable	**(14)**	(34)	33
-Accrued taxes	**14**	(11)	39
-Over recovered regulatory clause revenues	**(45)**	96	(18)
-Mirror CWIP	**—**	(271)	180
-Customer liability associated with Kemper refunds	**(73)**	73	—
-Other current liabilities	**36**	—	46
Net cash provided from operating activities	**229**	173	735
Investing Activities:			
Property additions	**(798)**	(857)	(1,257)
Investment in restricted cash	**—**	—	(11)
Distribution of restricted cash	**—**	—	11
Construction payables	**(26)**	(9)	(50)
Government grant proceeds	**137**	—	—
Other investing activities	**(10)**	(40)	(33)
Net cash used for investing activities	**(697)**	(906)	(1,340)
Financing Activities:			
Proceeds —			
Capital contributions from parent company	**627**	277	451
Bonds — Other	**—**	—	23
Interest-bearing refundable deposit	**—**	—	125
Long-term debt issuance to parent company	**200**	275	220
Other long-term debt	**1,200**	—	250
Short-term borrowings	**—**	505	—
Redemptions —			
Short-term borrowings	**(478)**	(5)	—
Long-term debt to parent company	**(225)**	—	(220)
Bonds — Other	**—**	—	(34)
Senior notes	**(300)**	—	—
Other long-term debt	**(425)**	(350)	—
Return of capital	**—**	—	(220)
Other financing activities	**(5)**	(4)	(2)
Net cash provided from financing activities	**594**	698	593
Net Change in Cash and Cash Equivalents	**126**	(35)	(12)

Cash and Cash Equivalents at Beginning of Year	**98**	133	145
Cash and Cash Equivalents at End of Year	**$ 224**	$ 98	$ 133
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $49, $66, and $69 capitalized, respectively)	**$ 50**	$ 45	$ 7
Income taxes (net of refunds)	**(97)**	(33)	(379)
Noncash transactions —			
Accrued property additions at year-end	**78**	105	114
Issuance of promissory note to parent related to repayment of interest-bearing refundable deposits and accrued interest	**—**	301	—

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2016 and 2015
Mississippi Power Company 2016 Annual Report

Assets	2016	2015
	(in millions)	
Current Assets:		
Cash and cash equivalents	$ 224	$ 98
Receivables —		
Customer accounts receivable	29	26
Unbilled revenues	42	36
Income taxes receivable, current	544	20
Other accounts and notes receivable	14	10
Affiliated	15	20
Fossil fuel stock	100	104
Materials and supplies, current	76	75
Other regulatory assets, current	115	95
Prepaid income taxes	—	39
Other current assets	8	8
Total current assets	1,167	531
Property, Plant, and Equipment:		
In service	4,865	4,886
Less accumulated provision for depreciation	1,289	1,262
Plant in service, net of depreciation	3,576	3,624
Construction work in progress	2,545	2,254
Total property, plant, and equipment	6,121	5,878
Other Property and Investments	12	11
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	361	290
Other regulatory assets, deferred	518	525
Income taxes receivable, non-current	—	544
Other deferred charges and assets	56	61
Total deferred charges and other assets	935	1,420
Total Assets	$ 8,235	$ 7,840

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2016 and 2015
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Liabilities and Stockholder's Equity	**2016**	2015
	(in millions)	
Current Liabilities:		
Securities due within one year —		
Parent	**$ 551**	$ —
Other	**78**	728
Notes payable	**23**	500
Accounts payable —		
Affiliated	**62**	85
Other	**135**	135
Customer deposits	**16**	16
Accrued taxes	**99**	85
Unrecognized tax benefits, current	**383**	—
Accrued interest	**46**	18
Accrued compensation	**42**	37
Asset retirement obligations, current	**32**	22
Over recovered regulatory clause liabilities	**51**	96
Customer liability associated with Kemper refunds	**1**	73
Other current liabilities	**19**	41
Total current liabilities	**1,538**	1,836
Long-Term Debt (See accompanying statements)	**2,424**	1,886
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**756**	762
Employee benefit obligations	**115**	153
Asset retirement obligations, deferred	**146**	154
Unrecognized tax benefits, deferred	**—**	368
Other cost of removal obligations	**170**	165
Other regulatory liabilities, deferred	**84**	79
Other deferred credits and liabilities	**26**	45
Total deferred credits and other liabilities	**1,297**	1,726
Total Liabilities	**5,259**	5,448
Cumulative Redeemable Preferred Stock (See accompanying statements)	**33**	33
Common Stockholder's Equity (See accompanying statements)	**2,943**	2,359
Total Liabilities and Stockholder's Equity	**$ 8,235**	$ 7,840
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CAPITALIZATION
At December 31, 2016 and 2015
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	2016	2015	**2016**	2015
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
2.35% due 2016	**$ —**	$ 300		
5.60% due 2017	**35**	35		
5.55% due 2019	**125**	125		
1.63% to 5.40% due 2035-2042	**680**	680		
Adjustable rates (1.84% to 1.90% at 1/1/16) due 2016	**—**	425		
Adjustable rates (2.15% to 2.24% at 1/1/17) due 2018	**1,200**	—		
Total long-term notes payable	**2,040**	1,565		
Other long-term debt —				
Pollution control revenue bonds —				
5.15% due 2028	**43**	43		
Variable rates (0.83% to 0.87% at 1/1/17) due 2017	**40**	40		
Plant Daniel revenue bonds (7.13%) due 2021	**270**	270		
Long-term debt payable to parent company (2.27%) due 2017	**551**	576		
Total other long-term debt	**904**	929		
Capitalized lease obligations	**74**	77		
Unamortized debt premium	**45**	53		
Unamortized debt discount	**(2)**	(2)		
Unamortized debt issuance expense	**(8)**	(8)		
Total long-term debt (annual interest requirement — $102 million)	**3,053**	2,614		
Less amount due within one year	**629**	728		
Long-term debt excluding amount due within one year	**2,424**	1,886	**44.9%**	44.1%
Cumulative Redeemable Preferred Stock:				
$100 par value —				
Authorized — 1,244,139 shares				
Outstanding — 334,210 shares				
4.40% to 5.25% (annual dividend requirement — $2 million)	**33**	33	**0.6**	0.8
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 1,130,000 shares				
Outstanding — 1,121,000 shares	**38**	38		
Paid-in capital	**3,525**	2,893		
Accumulated deficit	**(616)**	(566)		
Accumulated other comprehensive loss	**(4)**	(6)		
Total common stockholder's equity	**2,943**	2,359	**54.5**	55.1
Total Capitalization	**$ 5,400**	$ 4,278	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2016 , 2015 , and 2014
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	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total
				(in millions)		
Balance at December 31, 2013	1	$ 38	$ 2,377	$ (230)	$ (8)	$ 2,177
Net loss after dividends on preferred stock	—	—	—	(329)	—	(329)
Capital contributions from parent company	—	—	235	—	—	235
Other comprehensive income (loss)	—	—	—	—	1	1
Balance at December 31, 2014	1	38	2,612	(559)	(7)	2,084
Net loss after dividends on preferred stock	—	—	—	(8)	—	(8)
Capital contributions from parent company	—	—	281	—	—	281
Other comprehensive income (loss)	—	—	—	—	1	1
Other	—	—	—	1	—	1
Balance at December 31, 2015	**1**	**38**	**2,893**	**(566)**	**(6)**	**2,359**
Net loss after dividends on preferred stock	**—**	**—**	**—**	**(50)**	**—**	**(50)**
Capital contributions from parent company	**—**	**—**	**632**	**—**	**—**	**632**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**2**	**2**
Balance at December 31, 2016	**1**	**$ 38**	**$ 3,525**	**$ (616)**	**$ (4)**	**$ 2,943**

The accompanying notes are an integral part of these financial statements.

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Mississippi Power Company (the Company) is a wholly-owned subsidiary of Southern Company, which is the parent company of the Company and three other traditional electric operating companies, as well as Southern Power, Southern Company Gas (as of July 1, 2016), SCS, Southern LINC, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure, Inc. (PowerSecure) (as of May 9, 2016), and other direct and indirect subsidiaries. The traditional electric operating companies – Alabama Power, Georgia Power, Gulf Power, and the Company – are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electric service to retail customers in southeast Mississippi and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern LINC provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and for other electric services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.

The Company is subject to regulation by the FERC and the Mississippi PSC. As such, the Company's financial statements reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

Recently Issued Accounting Standards

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers,* replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

While the Company expects most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of such arrangements. The majority of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term. For such arrangements, the Company generally expects that the revenue from contracts with these customers will continue to be equivalent to the electricity supplied and billed in that period (including unbilled revenues) and the adoption of ASC 606 will not result in a significant shift in the timing of revenue recognition for such sales.

The Company's ongoing evaluation of other revenue streams and related contracts includes longer term contractual commitments and unregulated sales to customers. Some revenue arrangements, such as certain PPAs and alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on the Company's financial statements. In addition, the power and utilities industry is currently addressing other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). If final implementation guidance indicates CIAC will be accounted for under ASC 606 and offsetting regulatory treatment is not permitted, it could have a material impact on the Company's financial statements.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. The Company must select a transition method to be applied either retrospectively to each prior reporting period presented or retrospectively with a cumulative effect adjustment to retained earnings at the date of initial adoption. As the ultimate impact of the new standard has not yet been determined, the Company has not elected its transition method.

On February 25, 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged . ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company is currently evaluating

the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

On March 30, 2016, the FASB issued ASU No. 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Note s 5, 8, and 11 for disclosures impacted by ASU 2016-09.

On October 24, 2016, the FASB issued ASU No. 2016-16, *Income Taxes (Topic 740), Intra-Entity Transfers of Assets Other Than Inventory* (ASU 2016-16). Current GAAP prohibits the recognition of current and deferred income taxes for an affiliate asset transfer until the asset has been sold to an outside party. ASU 2016-16 requires an entity to recognize the income tax consequences of an affiliate transfer of an asset other than inventory when the transfer occurs. ASU 2016-16 is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. The amendments will be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The Company is currently assessing the impact of the standard on its financial statements and has not yet determined its ultimate impact.

In 2014, the FASB issued ASU No. 2014-15, *Presentation of Financial Statements-Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern* (ASU 2014-15). ASU 2014-15 defines management's responsibility to evaluate whether there is substantial doubt about an organization's ability to continue as a going concern within one year of the date the financial statements are issued and to provide related footnote disclosures including management's plans that alleviate substantial doubt. ASU 2014-15 became effective for fiscal years ending after December 15, 2016 and the Company has included the disclosures required by ASU 2014-15 in Note 6 under "Going Concern."

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Costs for these services amounted to $231 million , $295 million , and $259 million during 2016 , 2015 , and 2014 , respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has an agreement with Alabama Power under which the Company owns a portion of Greene County Steam Plant. Alabama Power operates Greene County Steam Plant, and the Company reimburses Alabama Power for its proportionate share of non-fuel expenditures and costs, which totaled $13 million , $11 million , and $13 million in 2016 , 2015 , and 2014 , respectively. Also, the Company reimburses Alabama Power for any direct fuel purchases delivered from an Alabama Power transfer facility. There were no fuel purchases in 2016. Fuel purchases were $8 million and $34 million in 2015 and 2014 , respectively. The Company also has an agreement with Gulf Power under which Gulf Power owns a portion of Plant Daniel. The Company operates Plant Daniel, and Gulf Power reimburses the Company for its proportionate share of all associated expenditures and costs, which totaled $26 million , $27 million , and $31 million in 2016 , 2015 , and 2014 , respectively. See Note 4 for additional information.

On June 27, 2016, the Company received a capital contribution from Southern Company of $225 million , the proceeds of which were used to repay to Southern Company a portion of the promissory note issued in November 2015. As of December 31, 2016 , the amount of outstanding promissory notes to Southern Company totaled $551 million . Also, on December 14, 2016, the Company received a capital contribution from Southern Company of $400 million , the proceeds of w hich were used for general corporate purposes. See Note 6 for additional information.

The Company also provides incidental services to and receives such services from other Southern Company subsidiaries which

are generally minor in duration and amount. Except as described he rein, the Company neither provided nor received any material services to or from affiliates in 2016 , 2015 , or 2014 .

The traditional electric operating companies, including the Company and S outhern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS, as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

Regulatory Assets and Liabilities

The Company is subject to accounting requirements for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2016	2015	Note
		(in millions)	
Kemper IGCC	**$ 201**	$ 216	(h)
Retiree benefit plans – regulatory assets	**173**	163	(a,g)
Asset retirement obligations	**83**	70	(c)
Deferred income tax charges	**362**	291	(c)
Remaining net book value of retired assets	**53**	36	(b)
Property tax	**37**	27	(d)
Plant Daniel Units 3 and 4	**33**	29	(j)
Other regulatory assets	**42**	27	(e,g)
Fuel-hedging (realized and unrealized) losses	**7**	50	(f,g)
Property damage	**(68)**	(64)	(i)
Other cost of removal obligations	**(170)**	(167)	(c)
Other regulatory liabilities	**(16)**	(11)	(b)
Total regulatory assets (liabilities), net	**$ 737**	$ 667	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Recovered and amortized over the average remaining service period which m ay range up to 14 years . See Note 2 for additional information.

(b) Other regulatory liabilities is comprised of numerous immaterial components including deferred income tax credits and other miscellaneous liabilities that are recorded and refunded or amortized as approved by the Mississippi PSC generally over periods not exceeding one year .

(c) Asset retirement and other cost of removal obligations and deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 49 years . Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(d) The retail portion of property taxes is recovered through the ad valorem tax adjustment clause over a 12 -month period beginning in April of the following year. See Note 3 under "Retail Regulatory Matters – Ad Valorem Tax Adjustment" for additional information.

(e) Other regulatory assets is comprised of numerous immaterial components including vacation pay, loss on reacquired debt, and other miscellaneous assets. These costs are recorded and recovered or amortized as approved by the Mississippi PSC over periods which may range up to 50 years.

(f) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed three years . Upon final settlement, actual costs incurred are recovered through the ECM.

(g) Not earning a return as offset in rate base by a corresponding asset or liability.

(h) Includes $97 million of regulatory assets currently in rates to be recovered over periods of two , seven , or 10 years . For additional information, see Note 3 under "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities."

(i) For additional information, see Note 1 under "Provision for Property Damage."

(j) The difference between the revenue requirement under the purchase option and the revenue requirement assuming operating lease accounting treatment for the extended term is d eferred and amortized over a 10 -year period beginning October 2021.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets

and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" and "Integrated Coal Gasification Combined Cycle" for additional information.

Government Grants

In 2010, the DOE, through a cooperative agr eement with SCS, agreed to fund $270 million of the Kemper IGCC through the grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (Initial DOE Grants). Through December 31, 2016 , the Company has received grant funds of $382 million , of which $245 million of the Initial DOE Grants were used for the construction of the Kemper IGCC, which is reflected in the Company's financial statements as a reduction to the Kemper IGCC capital costs, and $137 million received on April 8, 2016 (Additional DOE Grants), which are expected to be used to reduce future rate impacts. An additional $25 million is expected to be received for its initial operation. See Note 3 under "Kemper IGCC Schedule and Cost Estimate" for additional information.

Revenues

Energy and other revenues are recognized as services are provided. Wholesale capacity revenues from long-term contracts are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract period. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. The Company's retail and wholesale rates include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Retail rates also include provisions to adjust billings for fluctuations in costs for ad valorem taxes and certain qualifying environmental costs. Revenues are adjusted for differences between these actual costs and projected amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company is required to file with the Mississippi PSC for an adjustment to the fuel cost recovery, ad valorem, and environmental factors annually.

The Company serves long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based MRA electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represent ed 19.8% of the Company's total operating revenues in 2016 and are largely subject to rolling 10 -year cancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

Except as described above for the Company's cost-based MRA electric tariff customers, the Company has a diversified base of customers and no single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

See Note 3 under "Retail Regulatory Matters" for additional information.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel costs also include gains and/or losses from fuel-hedging programs as approved by the Mississippi PSC.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. ITCs utilized are deferred and amortized to income over the average life of the related property. T axes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of operations.

The Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction for projects where recovery of CWIP is not allowed in rates.

The Company's property, plant, and equipment in service consisted of the following at December 31:

	2016	2015
	(in millions)	
Generation	**$ 2,632**	$ 2,723
Transmission	**712**	688
Distribution	**916**	891
General	**520**	503
Plant acquisition adjustment	**85**	81
Total plant in service	**$ 4,865**	$ 4,886

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses except for all costs associated with operating and maintaining the Kemper IGCC assets already placed in service and a portion of the railway track maintenance costs. The portion of railway track maintenance costs not charged to operations and maintenance expenses are charged to fuel stock and recovered through the Company's fuel clause. Through July 2015, all costs associated with the combined cycle and the associated common facilities portion of the Kemper IGCC, excluding the lignite mine, were deferred to a regulatory asset that is being recovered over 10 years beginning August 2015. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

Depreciation, Depletion, and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 4.2% in 2016 , 4.7% in 2015 , and 3.3% in 2014 . The decrease in the 2016 depreciation rate is primarily due to fully depreciating and retiring the ARO at Plant Watson, partially offset by the increase in depreciation for the Plant Daniel scrubbers for a full year. The increase in the 2015 depreciation rate was primarily due to an ARO at Plant Watson incurred as a result of changes in environmental regulations. See "Asset Retirement Obligations and Other Costs of Removal" herein for additional information. Depreciation studies are conducted periodically to update the composite rates. The Mississippi PSC approved the 2014 study, with new rates effective January 1, 2015. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Depreciation includes an amount for the expected cost of removal of facilities, except for the Kemper IGCC assets in service.

The Kemper IGCC will be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation in June 2013. Depreciation associated with fixed assets, amortization associated with rolling stock, and depletion associated with minerals and minerals rights is recognized and charged to fuel stock and is expected to be recovered through the Company's fuel clause. Through July 2015, depreciation associated with the combined cycle and the associated common facilities portion of the Kemper IGCC was deferred as a regulatory asset that is being recovered over 10 years beginning August 2015. See Note 3 under "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" for additional information.

Asset Retirement Obligations and Other Costs of Removal

AROs are computed as the present value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. The Company has received accounting guidance from the Mississippi PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for AROs primarily relates to facilities that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in April 2015 (CCR Rule), principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, deep injection wells, water wells, substation removal, mine reclamation, and asbestos removal. The Company also has identified AROs related to certain transmission and

distribution facilities and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the AROs related to these assets is indeterminable and, therefore, the fair value of the AROs cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in th e statements of operations allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as e ither a regulatory asset or liability, as ordered by the Mississippi PSC, and are reflected in the balance sheets.

Details of the AROs included in the balance sheets are as follows:

	2016	2015
	(in millions)	
Balance at beginning of year	**$ 177**	$ 48
Liabilities incurred	**15**	101
Liabilities settled	**(23)**	(3)
Accretion	**5**	4
Cash flow revisions	**5**	27
Balance at end of year	**$ 179**	$ 177

The increase in liabilities incurred and cash flow revisions in 2015 primarily relate to an increase in AROs associated with facilities impacted by the CCR Rule located at Plant Watson and Plant Greene County.

The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 2016 using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing with respect to compliance activities, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the Company expects to continue to periodically update these estimates.

Allowance for Funds Used During Construction

The Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in the calculation of taxable income. The average annual AFUDC rate w as 6.50% , 5.99% , and 6.91% for the years ended December 31, 2016 , 2015 , and 2014 , respectively. AFUDC equity was $124 million , $110 million , and $136 million in 2016 , 2015 , and 2014 , respectively.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change. See Note 3 under "Integrated Coal Gasification Combined Cycle – Kemper IGCC Schedule and Cost Estimate" for additional information.

Provision for Property Damage

The Company carries insurance for the cost of certain types of damage to generation plants and general property. However, the Company is self-insured for the cost of storm, fire, and other uninsured casualty damage to its property, including transmission and distribution facilities. As permitted by the Mississippi PSC and the FERC, the Company accrues for the cost of such damage through an annual expense accrual credited to regulatory liability accounts for the retail and wholesale jurisdictions. The cost of repairing actual damage resulting from such events that individually exce ed $50,000 is charged to the reserve. Every three years the Mississippi PSC, the MPUS, and the Company will agree on SRR revenue level(s) for the ensuing period, based on historical data, expected exposure, type and amount of insurance coverage, excluding insurance cost, and any other relevant information.

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The accrual amount and the reserve balance are determined based on the SRR revenue level(s). If a significant change in circumstances occurs, then the SRR revenue level can be adjusted more frequently if the Company and the MPUS or the Mississippi PSC deem the change appropriate. The property damage reserve accrual will be the difference between the approved SRR revenues and the SRR revenue requirement, excluding any accrual to the reserve. In addition, SRR allows the Company to set up a regulatory asset, pending review, if the allowable actual retail property damage costs exceed the amount in the retail property damage reserve. The Company made retail accruals of $4 million for 2016 and $3 million for each of 2015 and 2014 . The Company also accrued $0.3 million annually in 2016 , 2015 , and 2014 for the wholesale jurisdiction. As of December 31, 2016 , the property damage reserve balances were $66 million and $1 million for retail and wholesa le, respectively.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, mining, and generating plant materials. Materials are charged to inventory when purchased and then expensed, capitalized to plant, or charged to fuel stock, as used, at weighted-average cost when utilized.

Fuel Inventory

Fuel inventory includes the average cost of coal, lignite, natural gas, oil, transportation, and emissions allowances. Fuel costs are recorded to inventory when purchased, except for the cost of owning and operating the lignite mine related to the Kemper IGCC which is charged to inventory as coal is mined, and then expensed, at weighted average cost, as used and recovered by the Company through fuel cost recovery rates or capitalized as part of the Kemper IGCC costs if used for testing. The retail rate is approved by the Mississippi PSC and the wholesale rates are approved by the FERC. Emissions allowances granted by the EPA are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, electricity purchases and sales, and occasionally foreign currency exchange rates. All derivative financial instruments are recognized as either assets or liabilities on the balance sheets (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from the fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Fuel and interest rate derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Mississippi PSC approved fuel-hedging program as discussed below result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Foreign currency exchange rate hedges are designated as fair value hedges. Settled foreign currency exchange hedges related to the Kemper IGCC are recorded in CWIP. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of operations. Cash flows from d erivatives are classified on the statement of cash flows in the same category as the hedged item. See Note 10 for additional information regarding derivatives.

Beginning in 2016, the Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a netting arrangement. Additionally, the Company's collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2016 are immaterial.

The Company has an ECM clause which, among other things, allows the Company to utilize financial instruments to hedge its fuel commitments. Changes in the fair value of these financial instruments are recorded as regulatory assets or liabilities. Amounts paid or received as a result of financial settlement of these instruments are classified as fuel expense and are included in the ECM factor applied to customer billings. The Company's jurisdictional wholesale customers have a similar ECM mechanism, which has been approved by the FERC.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

Variable Interest Entities

The primary beneficiary of a variable interest entity (VIE) is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

The Company is required to provide financing for all costs associated with the mine development and operation under a contract with Liberty Fuels Company, LLC, a subsidiary of North American Coal Corporation (Liberty Fuels), in conjunction with the construction of the Kemper IGCC. Liberty Fuels qualifies as a VIE for which the Company is the primary beneficiary. As of December 31, 2016 , the VIE consolidation resulted in an ARO asset and associated liability in the a mounts of $20 million and $24 million , respectively. As of December 31, 2015 , the VIE consolidation resulted in an ARO and an a ssociated liability in the amounts of $21 million and $25 million , respectively. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). On December 19, 2016, the Company voluntarily contributed $47 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2017 . The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2017 , no other postretirement trust contributions are expected.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the net periodic costs for the pension and other postretirement benefit plans for the following year and the benefit obligations as of the measurement date are presented below.

Assumptions used to determine net periodic costs:	2016	2015	2014
Pension plans			
Discount rate – benefit obligations	**4.69%**	4.17%	5.01%
Discount rate – interest costs	**3.97**	4.17	5.01
Discount rate – service costs	**5.04**	4.49	5.01
Expected long-term return on plan assets	**8.20**	8.20	8.20
Annual salary increase	**4.46**	3.59	3.59
Other postretirement benefit plans			
Discount rate – benefit obligations	**4.47%**	4.03%	4.85%
Discount rate – interest costs	**3.66**	4.03	4.85
Discount rate – service costs	**4.88**	4.38	4.85
Expected long-term return on plan assets	**7.07**	7.23	7.30
Annual salary increase	**4.46**	3.59	3.59

Assumptions used to determine benefit obligations:	2016	2015
Pension plans		
Discount rate	**4.44%**	4.69%
Annual salary increase	**4.46**	4.46
Other postretirement benefit plans		
Discount rate	**4.22%**	4.47%
Annual salary increase	**4.46**	4.46

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

NOTES (continued)
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An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2016 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	6.50%	4.50%	2025
Post-65 medical	5.00	4.50	2025
Post-65 prescription	10.00	4.50	2025

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2016 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 5	$ 4
Service and interest costs	—	—

Pension Plans

The total accumulated benefit obligation for the pension plans was $479 million at December 31, 2016 and $447 million at December 31, 2015 . Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2016 and 2015 were as follows:

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 500**	$ 513
Service cost	**13**	13
Interest cost	**19**	21
Benefits paid	**(20)**	(22)
Actuarial (gain) loss	**22**	(25)
Balance at end of year	**534**	500
Change in plan assets		
Fair value of plan assets at beginning of year	**430**	446
Actual return (loss) on plan assets	**39**	4
Employer contributions	**50**	2
Benefits paid	**(20)**	(22)
Fair value of plan assets at end of year	**499**	430
Accrued liability	**$ (35)**	$ (70)

At December 31, 2016 , the projected benefit obligations for the qualified and non-qualified pension plans were $504 million and $30 million , respectively. All pension plan assets are related to the qualified pension plan.

NOTES (continued)
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Amounts recognized in the balance sheets at December 31, 2016 and 2015 related to the Company's pension plans consist of the following:

	2016	2015
	(in millions)	
Other regulatory assets, deferred	$ 154	$ 144
Other current liabilities	(3)	(3)
Employee benefit obligations	(32)	(67)

Presented below are the amounts included in regulatory assets at December 31, 2016 and 2015 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2017 .

	2016	2015	Estimated Amortization in 2017
		(in millions)	
Prior service cost	$ 3	$ 2	$ 1
Net (gain) loss	151	142	7
Regulatory assets	$ 154	$ 144	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2016 and 2015 are presented in the following table:

	2016	2015
	(in millions)	
Regulatory assets:		
Beginning balance	$ 144	$ 151
Net (gain) loss	16	4
Change in prior service costs	2	—
Reclassification adjustments:		
Amortization of prior service costs	(1)	(1)
Amortization of net gain (loss)	(7)	(10)
Total reclassification adjustments	(8)	(11)
Total change	10	(7)
Ending balance	$ 154	$ 144

Components of net periodic pension cost were as follows:

	2016	2015	2014
		(in millions)	
Service cost	$ 13	$ 13	$ 10
Interest cost	19	21	20
Expected return on plan assets	(35)	(33)	(29)
Recognized net (gain) loss	7	10	5
Net amortization	1	1	1
Net periodic pension cost	$ 5	$ 12	$ 7

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2016 , estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2017	$ 22
2018	23
2019	24
2020	26
2021	27
2022 to 2026	154

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2016 and 2015 were as follows:

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 97**	$ 96
Service cost	**1**	1
Interest cost	**3**	4
Benefits paid	**(6)**	(5)
Actuarial (gain) loss	**1**	(1)
Plan amendment	**—**	1
Retiree drug subsidy	**1**	1
Balance at end of year	**97**	97
Change in plan assets		
Fair value of plan assets at beginning of year	**23**	24
Actual return (loss) on plan assets	**1**	—
Employer contributions	**4**	3
Benefits paid	**(5)**	(4)
Fair value of plan assets at end of year	**23**	23
Accrued liability	**$ (74)**	$ (74)

Amounts recognized in the balance sheets at December 31, 2016 and 2015 related to the Company's other postretirement benefit plans consist of the following:

	2016	2015
	(in millions)	
Other regulatory assets, deferred	**$ 21**	$ 21
Other regulatory liabilities, deferred	**(2)**	(3)
Employee benefit obligations	**(74)**	(74)

NOTES (continued)
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Approximately $19 million and $18 million was included in net regulatory assets at December 31, 2016 and 2015 , respectively, related to the net loss for the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost. The estimated amortization of such amounts for 2017 is $1 million .

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2016 and 2015 are presented in the following table:

	2016	2015
	(in millions)	
Net regulatory assets (liabilities):		
Beginning balance	**$ 18**	$ 16
Net (gain) loss	**2**	—
Change in prior service costs	**—**	3
Reclassification adjustments:		
Amortization of net gain (loss)	**(1)**	(1)
Total reclassification adjustments	**(1)**	(1)
Total change	**1**	2
Ending balance	**$ 19**	$ 18

Components of the other postretirement benefit plans' net periodic cost were as follows:

	2016	2015	2014
		(in millions)	
Service cost	**$ 1**	$ 1	$ 1
Interest cost	**3**	4	4
Expected return on plan assets	**(1)**	(2)	(2)
Net amortization	**1**	1	—
Net periodic postretirement benefit cost	**$ 4**	$ 4	$ 3

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	**Subsidy Receipts**	**Total**
		(in millions)	
2017	$ 6	$ (1)	$ 5
2018	6	(1)	5
2019	7	(1)	6
2020	7	(1)	6
2021	7	(1)	6
2022 to 2026	36	(1)	35

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

NOTES (continued)
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The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2016 and 2015 , along with the targeted mix of assets for each plan, is presented below:

	Target	**2016**	2015
Pension plan assets:			
Domestic equity	26%	**29%**	30%
International equity	25	**22**	23
Fixed income	23	**29**	23
Special situations	3	**2**	2
Real estate investments	14	**13**	16
Private equity	9	**5**	6
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	21%	**23%**	24%
International equity	20	**18**	18
Domestic fixed income	38	**43**	38
Special situations	3	**2**	2
Real estate investments	11	**10**	13
Private equity	7	**4**	5
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2016 and 2015 . The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management

relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- ***Domestic and international equity.*** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- ***Fixed income.*** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- ***Real estate investments, private equity, and special situations investments.*** Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

The fair values of pension plan assets as of December 31, 2016 and 2015 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. For 2015, investments in special situations were presented in the table below based on the nature of the investment.

	Fair Value Measurements Using				
As of December 31, 2016:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Assets:					
Domestic equity (*)	$ 95	$ 44	$ —	$ —	$ 139
International equity (*)	58	51	—	—	109
Fixed income:					
U.S. Treasury, government, and agency bonds	—	28	—	—	28
Mortgage- and asset-backed securities	—	1	—	—	1
Corporate bonds	—	46	—	—	46
Pooled funds	—	25	—	—	25
Cash equivalents and other	47	—	—	—	47
Real estate investments	15	—	—	54	69
Special situations	—	—	—	8	8
Private equity	—	—	—	26	26
Total	$ 215	$ 195	$ —	$ 88	$ 498

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

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As of December 31, 2015:	Fair Value Measurements Using				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Assets:					
Domestic equity (*)	$ 76	$ 32	$ —	$ —	$ 108
International equity (*)	55	46	—	—	101
Fixed income:					
U.S. Treasury, government, and agency bonds	—	21	—	—	21
Mortgage- and asset-backed securities	—	9	—	—	9
Corporate bonds	—	53	—	—	53
Pooled funds	—	23	—	—	23
Cash equivalents and other	—	7	—	—	7
Real estate investments	14	—	—	57	71
Private equity	—	—	—	30	30
Total	$ 145	$ 191	$ —	$ 87	$ 423

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

The fair values of other postretirement benefit plan assets as of December 31, 2016 and 2015 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

As of December 31, 2016:	Fair Value Measurements Using				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Assets:					
Domestic equity (*)	$ 4	$ 2	$ —	$ —	$ 6
International equity (*)	2	2	—	—	4
Fixed income:					
U.S. Treasury, government, and agency bonds	—	5	—	—	5
Mortgage- and asset-backed securities	—	—	—	—	—
Corporate bonds	—	2	—	—	2
Pooled funds	—	1	—	—	1
Cash equivalents and other	2	—	—	—	2
Real estate investments	1	—	—	2	3
Private equity	—	—	—	1	1
Total	$ 9	$ 12	$ —	$ 3	$ 24

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2015:	Fair Value Measurements Using				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
	(in millions)				
Assets:					
Domestic equity (*)	$ 3	$ 1	$ —	$ —	$ 4
International equity (*)	2	2	—	—	4
Fixed income:					
U.S. Treasury, government, and agency bonds	—	6	—	—	6
Mortgage- and asset-backed securities	—	—	—	—	—
Corporate bonds	—	2	—	—	2
Pooled funds	—	1	—	—	1
Cash equivalents and other	1	—	—	—	1
Real estate investments	1	—	—	3	4
Private equity	—	—	—	1	1
Total	$ 7	$ 12	$ —	$ 4	$ 23

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2016 , 2015 , and 2014 were $5 million each year.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up affected sites. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through established regulatory mechanisms.

FERC Matters

Municipal and Rural Associations Tariff

In 2013, the FERC accepted a settlement agreement entered into by the Company with its wholesale customers which approved, among other things, the same regulatory treatment for tariff ratemaking as the treatment approved for retail ratemaking by the Mississippi PSC for certain items. The regulatory treatment includes (i) approval to establish a regulatory asset for the portion of non-capitalizable Kemper IGCC-related costs which have been and will continue to be incurred during the construction period for the Kemper IGCC, (ii) authorization to defer as a regulatory asset, for the 10 -year period ending October 2021, the difference between the revenue requirement under the purchase option of Plant Daniel Units 3 and 4 (assuming a remaining 30 -year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into wholesale rates over the remaining life of Plant Daniel Units 3 and 4, and (iii) authority to defer in a regulatory asset costs related to the retirement or partial retirement of generating units as a result of environmental compliance rules.

In 2014, the Company reached, and the FERC accepted, a settlement agreement with its wholesale customers for an estimated annual increase in the MRA cost-based tariff of approximately $10 million , effective May 1, 2014. Included in this settlement agreement was a mechanism allowing the Company to adjust the wholesale revenue requirement in a subsequent rate proceeding in the event the Kemper IGCC, or any substantial portion thereof, was placed in service before or after December 1, 2014. Therefore, the Company recorded a regulatory asset as a result of a portion of the Kemper IGCC being placed in service prior to the projected date, which was fully amortized as of December 31, 2015.

In May 2015, the FERC accepted a further settlement agreement between the Company and its wholesale customers to forgo a MRA cost-based electric tariff increase by, among other things, increasing the accrual of AFUDC and lowering the portion of CWIP in rate base, effective April 1, 2015, resulting in an estimated annual AFUDC increase of approximately $14 million , of which approximately $11 million is related to the Kemper IGCC.

On March 31, 2016, the Company reached a settlement agreement with its wholesale customers, which was subsequently approved by the FERC, for an increase in wholesale base revenues under the MRA cost-based electric tariff, primarily as a result of placing scrubbers for Plant Daniel Units 1 and 2 in service in November 2015. The settlement agreement became effective for services rendered beginning May 1, 2016, resulting in an estimated annual revenue increase of $7 million under the MRA cost-based electric tariff. Additionally, under the settlement agreement, the tariff customers agreed to similar regulatory treatment for MRA tariff ratemaking as the treatment approved for retail ratemaking through an order issued by the Mississippi PSC in December 2015 (In-Service Asset Rate Order). This regulatory treatment primarily includes (i) recovery of the Kemper IGCC assets currently operational and providing service to customers and other related costs, (ii) amortization of the Kemper IGCC-related regulatory assets included in rates under the settlement agreement over the 36 months ending April 30, 2019, (iii) Kemper IGCC-related expenses included in rates under the settlement agreement no longer being deferred and charged to expense, and (iv) removing all of the Kemper IGCC CWIP from rate base with a corresponding increase in accrual of AFUDC. The additional resulting AFUDC is estimated to be approximately $14 million through the Kemper IGCC's projected in-service date of mid-March 2017.

Fuel Cost Recovery

The Company has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective with the first billing cycle for September 2016, fuel rates decreased $11 million annually for wholesale MRA customers and $1 million annually for wholesale MB customers. At December 31, 2016 and 2015, the amount of over recovered wholesale MRA fuel costs were approximately $13 million and $24 million , respectively, which is included in over recovered regulatory clause liabilities, current in the balance sheets. Effective January 1, 2017, the wholesale MRA fuel rate increased $10 million annually.

The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on the Company's revenues or net income, but will affect cash flow.

Market-Based Rate Authority

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric operating companies' (including the Company's) and Southern Power's existing

tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies (including the Company) and Southern Power filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.

On December 9, 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. The traditional electric operating companies (including the Company) and Southern Power expect to make a compliance filing within 30 days accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

The ultimate outcome of these matters cannot be determined at this time.

Retail Regulatory Matters

General

In 2012, the Mississippi PSC issued an order for the purpose of investigating and reviewing, for informational purposes only, the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. In 2013, the MPUS filed with the Mississippi PSC its report on the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. The ultimate outcome of this matter cannot be determined at this time.

Performance Evaluation Plan

The Company's retail base rates are set under the PEP, a rate plan approved by the Mississippi PSC. Two filings are made for each calendar year: the PEP projected filing, which is typically filed prior to the beginning of the year based on a projected revenue requirement, and the PEP lookback filing, which is filed after the end of the year and allows for review of the actual revenue requirement compared to the projected filing.

In 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. Later in 2011, the Company received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. In 2012, the Mississippi PSC issued an order canceling the Company's PEP lookback filing for 2011. I n 2013, the MPUS contested the Company's PEP lookback filing for 2012, which indicated a refund due to customers of $5 million . Unresolved matters related to the 2010 PEP lookback filing, which remain under review, also impact the 2012 PEP lookback filing.

In 2013, the Mississippi PSC approved the projected PEP filing for 2013, which resulted in a rate increase of 1.9% , or $15 million , annually, effective March 19, 2013. The Company may be entitled to $3 million in additional revenues related to 2013 as a result of the late implementation of the 2013 PEP rate increase.

In 2014, 2015, and 2016, the Company submitted its annual PEP lookback filings for the prior years, which for 2013 and 2014 each indicated no surcharge or refund and for 2015 indicated a $5 million surcharge. On July 12, 2016 and November 15, 2016, the Company submitted its annual projected PEP filings for 2016 and 2017, respectively, which each indicated no change in rates. The Mississippi PSC suspended each of these filings to allow more time for review.

In 2014, the Mississippi PSC issued an order for the purpose of investigating and reviewing the adoption of a uniform formula rate plan for the Company and other regulated electric utilities in Mississippi.

The ultimate outcome of these matters cannot be determined at this time.

Energy Efficiency

In 2013, the Mississippi PSC approved an energy efficiency and conservation rule requiring electric and gas utilities in Mississippi serving more than 25,000 customers to implement energy efficiency programs and standards. Quick Start Plans, which include a portfolio of energy efficiency programs that are intended to provide benefits to a majority of customers, were required to be filed within six months of the order and will be in effect for two to three years .

On May 3, 2016, the Mississippi PSC issued an order approving the Company's Energy Efficiency Cost Rider Compliance filing, which reduced annual retail revenues by approximately $2 million effective with the first billing cycle for June 2016.

On November 30, 2016, the Company submitted its Energy Efficiency Cost Rider Compliance filing, which included an increase of $1 million in annual retail revenues. The ultimate outcome of this matter cannot be determined at this time.

Environmental Compliance Overview Plan

In 2012, the Mississippi PSC approved the Company's request for a CPCN to construct scrubbers on Plant Daniel Units 1 and 2, which were placed in service in November 2015. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. In 2014, the Company entered into a settlement agreement with the Sierra Club that, among other things, required the Sierra Club to dismiss or withdraw all pending legal and regulatory challenges to the issuance of the CPCN to construct scrubbers on Plant Daniel Units 1 and 2, which also occurred in 2014. In addition, and consistent with the Company's ongoing evaluation of recent environmental rules and regulations, the Company agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source Plant Sweatt Units 1 and 2 (80 MWs) no later than December 2018 (and the units were retired in July 2016). The Company also agreed that it would cease burning coal and other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and begin operating those units solely on natural gas no later than April 2015 (which occurred in April 2015) and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) no later than April 2016 (which occurred in February and March 2016, respectively) and begin operating those units solely on natural gas (which occurred in June and July 2016, respectively).

In accordance with a 2011 accounting order from the Mississippi PSC, the Company has the authority to defer in a regulatory asset for future recovery all plant retirement- or partial retirement-related costs resulting from environmental regulations. As of December 31, 2016, $17 million of Plant Greene County costs have been reclassified as regulatory assets and are expected to be recovered through the ECO plan and other existing cost recovery mechanisms over a period to be determined by the Mississippi PSC. The Mississippi PSC approved $41 million of costs that were reclassified to a regulatory asset associated with Plant Watson for amortization over a five -year period that began in July 2016. As a result, these decisions are not expected to have a material impact on the Company's financial statements.

On August 17, 2016, the Mississippi PSC approved the Company's revised ECO plan filing for 2016, which requested the maximum 2% annual increase in revenues, approximately $18 million , primarily related to the Plant Daniel Units 1 and 2 scrubbers being placed in service in November 2015. The revised rates became effective with the first billing cycle for September 2016. Approximately $22 million of related revenue requirements in excess of the 2% maximum was deferred for inclusion in the 2017 filing **.**

On February 14, 2017, the Company submitted its ECO plan filing for 2017, which requested an increase in annual revenues over 2016, capped at 2% of total retail revenues, of approximately $18 million , primarily related to the Plant Daniel Units 1 and 2 scrubbers placed in service in November 2015. The revenue requirement in excess of the 2% , approximately $27 million plus carrying costs, will be carried forward to the 2018 filing. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually. The Mississippi PSC approved the 2016 retail fuel cost recovery factor, effective January 5, 2016, which resulted in an annual revenue decrease of approximately $120 million . On August 17, 2016, the Mississippi PSC approved an additional decrease of $51 million annually in fuel cost recovery rates effective with the first billing cycle for September 2016. At December 31, 2016 and 2015, over recovered retail fuel costs were approximately $37 million and $71 million , respectively, which is included in over recovered regulatory clause liabilities, current in the balance sheets. On January 12, 2017, the Mississippi PSC approved the 2017 retail fuel cost recovery factor, effective February 2017 through January 2018, which will result in an annual revenue increase of approximately $55 million .

The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on the Company's revenues or net income, but will affect cash flow.

Ad Valorem Tax Adjustment

The Company establishes, annually, an ad valorem tax adjustment factor that is approved by the Mississippi PSC to collect the ad valorem taxes paid by the Company. On June 17, 2016, the Mississippi PSC approved the Company's annual ad valorem tax adjustment factor filing for 2016, which included an annual rate decrease of 0.07% , or $1 million in annual retail revenues, primarily due to the prior year over recovery.

System Restoration Rider

In October 2015, the Mississippi PSC approved the Company's 2015 SRR rate filing, which proposed that the SRR rate remain level at zero and the Company continue to accrue $3 million annually to the property damage reserve.

On February 1, 2016, the Company submitted its 2016 SRR rate filing which proposed no changes to either the SRR rate or the annual property damage reserve accrual. On February 19, 2016, the filing was suspended by the Mississippi PSC for review. The ultimate outcome of this matter cannot be determined at this time.

On February 3, 2017, the Company submitted its 2017 SRR rate filing, which proposed that the rate level remain at zero and the Company be allowed to accrue $4 million annually to the property damage reserve in 2017. The ultimate outcome of this matter cannot be determined at this time.

See Note 1 under "Provision for Property Damage" for additional information.

Storm Damage Cost Recovery

In connection with the damage associated with Hurricane Katrina, the Mississippi PSC authorized the issuance of system restoration bonds in 2006. In accordance with a Mississippi PSC order dated January 24, 2017, the Company has adjusted the System Restoration Charge implemented after Hurricane Katrina to zero . Upon completion of the proper defeasance process by the Mississippi State Bond Commission, the Company's obligations in relation to system restoration bonds issued after Hurricane Katrina in 2005 will be completely satisfied.

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

The Kemper IGCC utilizes IGCC technology with an expected output capacity of 582 MWs. The Kemper IGCC is fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation in 2013. In connection with the Kemper IGCC, the Company constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the transport of captured CO_2 for use in enhanced oil recovery.

Kemper IGCC Schedule and Cost Estimate

In 2012, the Mississippi PSC issued the 2012 MPSC CPCN Order, a detailed order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC . The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC CPCN Order was $2.4 billion , net of $245 million of Initial DOE Grants and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and AFUDC related to the Kemper IGCC. The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion , with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. The Kemper IGCC was originally projected to be placed in service in May 2014. The Company placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service in August 2014. The remainder of the plant, including the gasifiers and the gas clean-up facilities, represents first-of-a-kind technology. The initial production of syngas began on July 14, 2016 for gasifier "B" and on September 13, 2016 for gasifier "A." The Company achieved integrated operation of both gasifiers on January 29, 2017, including the production of electricity from syngas in both combustion turbines. The Company subsequently completed a brief outage to repair and make modifications to further improve the plant's ability to achieve sustained operations sufficient to support placing the plant in service for customers. Efforts to reach sustained operation of both gasifiers and production of electricity from syngas in both combustion turbines are in process. The plant has produced and captured CO_2 , and has produced sulfuric acid and ammonia, all of acceptable quality under the related off-take agreements. On February 20, 2017, the Company determined gasifier "B," which has been producing syngas over 60% of the time since early November 2016, requires an outage to remove ash deposits from its ash removal system. Gasifier "A" and combustion turbine "A" are expected to remain in operation, producing electricity from syngas, as well as producing chemical by-products. As a result, the Company currently expects the remainder of the Kemper IGCC, including both gasifiers, will be placed in service by mid-March 2017.

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The Company's Kemper IGCC 2010 project estimate, current cost estimate (which includes the impacts of the Mississippi Supreme Court's (Court) decision discussed herein under "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order"), and actual costs incurred as of December 31, 2016, all of which include 100% of the costs for the Kemper IGCC, are as follows:

Cost Category	2010 Project Estimate [a]	Current Cost Estimate [b]	**Actual Costs**
		(in billions)	
Plant Subject to Cost Cap [c][e]	$ 2.40	$ 5.64	**$ 5.44**
Lignite Mine and Equipment	0.21	0.23	**0.23**
CO_2 Pipeline Facilities	0.14	0.11	**0.11**
AFUDC [d]	0.17	0.79	**0.75**
Combined Cycle and Related Assets Placed in Service – Incremental [e]	—	0.04	**0.04**
General Exceptions	0.05	0.10	**0.09**
Deferred Costs [e]	—	0.22	**0.21**
Additional DOE Grants [f]	—	(0.14)	**(0.14)**
Total Kemper IGCC [g]	$ 2.97	$ 6.99	**$ 6.73**

(a) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities approved in 2011 by the Mississippi PSC, as well as the lignite mine and equipment, AFUDC, and general exceptions.

(b) Amounts in the Current Cost Estimate include certain estimated post-in-service costs which are expected to be subject to the cost cap.

(c) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion , net of the Initial DOE Grants and excluding the cost of the lignite mine and equipment, the cost of the CO2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when the Company demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions). The Current Cost Estimate and the Actual Costs include non-incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service in August 2014 that are subject to the $2.88 billion cost cap and exclude post-in-service costs for the lignite mine. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" herein for additional information.

(d) The Company's 2010 Project Estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC as described in "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order." The Current Cost Estimate also reflects the impact of a settlement agreement with the wholesale customers for cost-based rates under FERC's jurisdiction. See "FERC Matters" herein for additional information.

(e) Non-capital Kemper IGCC-related costs incurred during construction were initially deferred as regulatory assets. Some of these costs are now included in rates and are being recognized through income; however, such costs continue to be included in the Current Cost Estimate and the Actual Costs at December 31, 2016. The wholesale portion of debt carrying costs, whether deferred or recognized through income, is not included in the Current Cost Estimate and the Actual Costs at December 31, 2016. See "Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities" herein for additional information.

(f) On April 8, 2016, the Company received approximately $137 million in Additional DOE Grants, which are expected to be used to reduce future rate impacts for customers.

(g) The Current Cost Estimate and the Actual Costs include $2.76 billion that will not be recovered for costs above the cost cap, $0.83 billion of investment costs included in current rates for the combined cycle and related assets in service, and $0.08 billion of costs that were previously expensed for the combined cycle and related assets in service. The Current Cost Estimate and the Actual Costs exclude $0.25 billion of costs not included in current rates for post-June 2013 mine operations, the lignite fuel inventory, and the nitrogen plant capital lease, which will be included in the 2017 Rate Case to be filed by June 3, 2017. See Note 1 under "Fuel Inventory," Note 6 under "Capital Leases," and "Rate Recovery of Kemper IGCC Costs – 2017 Rate Case" herein for additional information.

Of the total costs, including post-in-service costs for the lignite mine, incurred as of December 31, 2016 , $3.67 billion was included in property, plant, and equipment (which is net of the Initial DOE Grants, the Additional DOE Grants, and estimated probable losses of $2.84 billion), $6 million in other property and investments, $75 million in fossil fuel stock, $47 million in materials and supplies, $29 million in other regulatory assets, current, $172 million in other regulatory assets, deferred, $3 million in other current assets, and $14 million in other deferred charges and assets in the balance sheet.

The Company does not intend to seek rate recovery for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. The Company recorded pre-tax charges to income for revisions to the cost estimate of $348 million ($215 million after tax), $365 million ($226 million after tax), and $868 million ($536 million after tax) in 2016, 2015, and 2014, respectively. Since 2012, in the aggregate, the Company has incurred charges of $2.76 billion ($1.71 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2016. The increases to the cost estimate in 2016 primarily reflect $186 million for the

extension of the Kemper IGCC's projected in-service date from August 31, 2016 to March 15, 2017 and $162 million for increased efforts related to operational readiness and challenges in start-up and commissioning activities, including the cost of repairs and modifications to both gasifiers, mechanical improvements to coal feed and ash management systems, and outage work, as well as certain post-in-service costs expected to be subject to the cost cap.

In addition to the current construction cost estimate, the Company is identifying potential improvement projects that ultimately may be completed subsequent to placing the remainder of the Kemper IGCC in service. If completed, such improvement projects would be expected to enhance plant performance, safety, and/or operations. As of December 31, 2016, approximately $12 million of related potential costs has been included in the estimated loss on the Kemper IGCC. Other projects have yet to be fully evaluated, have not been included in the current cost estimate, and may be subject to the $2.88 billion cost cap.

Any extension of the in-service date beyond mid-March 2017 is currently estimated to result in additional base costs of approximately $25 million to $35 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. Additional costs may be required for remediation of any further equipment and/or design issues identified. Any extension of the in-service date with respect to the Kemper IGCC beyond mid-March 2017 would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $16 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees of approximately $3 million per month. For additional information, see "2015 Rate Case" herein.

Further cost increases and/or extensions of the expected in-service date may result from factors including, but not limited to, difficulties integrating the systems required for sustained operations, sustaining nitrogen supply, major equipment failure, unforeseen engineering or design problems including any repairs and/or modifications to systems, and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC). Any further changes in the estimated costs of the Kemper IGCC subject to the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the Company's statements of income and these changes could be material.

Rate Recovery of Kemper IGCC Costs

Given the variety of potential scenarios and the uncertainty of the outcome of future regulatory proceedings with the Mississippi PSC (and any subsequent related legal challenges), the ultimate outcome of the rate recovery matters discussed herein, including the resolution of legal challenges, cannot now be determined but could result in further material charges that could have a material impact on the Company's results of operations, financial condition, and liquidity.

As of December 31, 2016, in addition to the $2.76 billion of costs above the Mississippi PSC's $2.88 billion cost cap that have been recognized as a charge to income, the Company had incurred approximately $1.99 billion in costs subject to the cost cap and approximately $1.46 billion in Cost Cap Exceptions related to the construction and start-up of the Kemper IGCC that are not included in current rates. These costs primarily relate to the following:

Cost Category	**Actual Costs**
	(in billions)
Gasifiers and Gas Clean-up Facilities	$ 1.88
Lignite Mine Facility	0.31
CO_2 Pipeline Facilities	0.11
Combined Cycle and Common Facilities	0.16
AFUDC	0.69
General exceptions	0.07
Plant inventory	0.03
Lignite inventory	0.08
Regulatory and other deferred assets	0.12
Subtotal	3.45
Additional DOE Grants	(0.14)
Total	**$ 3.31**

Of these amounts, approximately 29% is related to wholesale and approximately 71% is related to retail, including the 15% portion that was previously contracted to be sold to SMEPA. The Company and its wholesale customers have generally agreed to

the similar regulatory treatment for wholesale tariff purposes as approved by the Mississippi PSC for retail for Kemper IGCC-related costs. See "FERC Matters – Municipal and Rural Associations Tariff" and "Termination of Proposed Sale of Undivided Interest" herein for further information.

Prudence

On August 17, 2016, the Mississippi PSC issued an order establishing a discovery docket to manage all filings related to the prudence of the Kemper IGCC. On October 3, 2016, the Company made a required compliance filing, which included a review and explanation of differences between the Kemper IGCC project estimate set forth in the 2010 CPCN proceedings and the most recent Kemper IGCC project estimate, as well as comparisons of current cost estimates and current expected plant operational parameters to the estimates presented in the 2010 CPCN proceedings for the first five years after the Kemper IGCC is placed in service. Compared to amounts presented in the 2010 CPCN proceedings, operations and maintenance expenses have increased an average of $105 million annually and maintenance capital has increased an average of $44 million annually for the first full five years of operations for the Kemper IGCC. Additionally, while the current estimated operational availability estimates reflect ultimate results similar to those presented in the 2010 CPCN proceedings, the ramp up period for the current estimates reflects a lower starting point and a slower escalation rate. On November 17, 2016, the Company submitted a supplemental filing to the October 3, 2016 compliance filing to present revised non-fuel operations and maintenance expense projections for the first year after the Kemper IGCC is placed in service. This supplemental filing included approximately $68 million in additional estimated operations and maintenance costs expected to be required to support the operations of the Kemper IGCC during that period. The Company will not seek recovery of the $68 million in additional estimated costs from customers if incurred.

The Company expects the Mississippi PSC to address these matters in connection with the 2017 Rate Case.

Economic Viability Analysis

In the fourth quarter 2016, as a part of its Integrated Resource Plan process, the Southern Company system completed its regular annual updated fuel forecast, the 2017 Annual Fuel Forecast. This updated fuel forecast reflected significantly lower long-term estimated costs for natural gas than were previously projected.

As a result of the updated long-term natural gas forecast, as well as the revised operating expense projections reflected in the discovery docket filings discussed above, on February 21, 2017, the Company filed an updated project economic viability analysis of the Kemper IGCC as required under the 2012 MPSC CPCN Order confirming authorization of the Kemper IGCC. The project economic viability analysis measures the life cycle economics of the Kemper IGCC compared to feasible alternatives, natural gas combined cycle generating units, under a variety of scenarios and considering fuel, operating and capital costs, and operating characteristics, as well as federal and state taxes and incentives. The reduction in the projected long-term natural gas prices in the 2017 Annual Fuel Forecast and, to a lesser extent, the increase in the estimated Kemper IGCC operating costs, negatively impact the updated project economic viability analysis.

The Company expects the Mississippi PSC to address this matter in connection with the 2017 Rate Case.

2017 Accounting Order Request

After the remainder of the plant is placed in service, AFUDC equity of approximately $11 million per month will no longer be recorded in income, and the Company expects to incur approximately $25 million per month in depreciation, taxes, operations and maintenance expenses, interest expense, and regulatory costs in excess of current rates. The Company expects to file a request for authority from the Mississippi PSC and the FERC to defer all Kemper IGCC costs incurred after the in-service date that cannot be capitalized, are not included in current rates, and are not required to be charged against earnings as a result of the $2.88 billion cost cap until such time as the Mississippi PSC completes its review and includes the resulting allowable costs in rates. In the event that the Mississippi PSC does not grant the Company's request, these monthly expenses will be charged to income as incurred and will not be recoverable through rates.

2017 Rate Case

The Company continues to believe that all costs related to the Kemper IGCC have been prudently incurred in accordance with the requirements of the 2012 MPSC CPCN Order. The Company also recognizes significant areas of potential challenge during future regulatory proceedings (and any subsequent, related legal challenges) exist. As described further herein and under "Prudence," "Lignite Mine and CO_2 Pipeline Facilities," "Termination of Proposed Sale of Undivided Interest," "Bonus Depreciation," "Investment Tax Credits," and "Section 174 Research and Experimental Deduction," these challenges include, but are not limited to, prudence issues associated with capital costs, financing costs (AFUDC), and future operating costs net of chemical revenues; potential operating parameters; income tax issues; costs deferred as regulatory assets; and the 15% portion of the project previously contracted to SMEPA.

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Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization of up to $1.0 billion of prudently-incurred costs was enacted into law in 2013. The Company expects to utilize this legislation to securitize prudently-incurred qualifying facility costs in excess of the certificated cost estimate of $2.4 billion . Qualifying facility costs include, but are not limited to, pre-construction costs, construction costs, regulatory costs, and accrued AFUDC. The Court's decision regarding the 2013 MPSC Rate Order did not impact the Company's ability to utilize alternate financing through securitization or the February 2013 legislation.

Although the 2017 Rate Case has not yet been filed and is subject to future developments with either the Kemper IGCC or the Mississippi PSC, consistent with its approach in the 2013 and 2015 rate proceedings in accordance with the law passed in 2013 authorizing multi-year rate plans, the Company is developing both a traditional rate case requesting full cost recovery of the amounts not currently in rates and a rate mitigation plan that together represent the Company's probable filing strategy. The Company also expects that timely resolution of the 2017 Rate Case will likely require a negotiated settlement agreement. In the event an agreement acceptable to both the Company and the MPUS (and other parties) can be negotiated and ultimately approved by the Mississippi PSC, it is reasonably possible that full regulatory recovery of all Kemper IGCC costs will not occur. The impact of such an agreement on the Company's financial statements would depend on the method, amount, and type of cost recovery ultimately excluded. Certain costs, including operating costs, would be recorded to income in the period incurred, while other costs, including investment-related costs, would be charged to income when it is probable they will not be recovered and the amounts can be reasonably estimated. In the event an agreement acceptable to the parties cannot be reached, the Company intends to fully litigate its request for full recovery through the Mississippi PSC regulatory process and any subsequent legal challenges.

The Company has evaluated various scenarios in connection with its processes to prepare the 2017 Rate Case and has recognized an additional $80 million charge to income, which is the estimated minimum probable amount of the $3.31 billion of Kemper IGCC costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017.

2015 Rate Case

On August 13, 2015, the Mississippi PSC approved the Company's request for interim rates, which presented an alternative rate proposal (In-Service Asset Proposal) designed to recover the Company's costs associated with the Kemper IGCC assets that are commercially operational and currently providing service to customers (the transmission facilities, combined cycle, natural gas pipeline, and water pipeline) and other related costs. The interim rates were designed to collect approximately $159 million annually and became effective in September 2015, subject to refund and certain other conditions.

On December 3, 2015, the Mississippi PSC issued the In-Service Asset Rate Order adopting in full a stipulation (2015 Stipulation) entered into between the Company and the MPUS regarding the In-Service Asset Proposal. The In-Service Asset Rate Order provided for retail rate recovery of an annual revenue requirement of approximately $126 million , based on the Company's actual average capital structure, with a maximum common equity percentage of 49.733% , a 9.225% return on common equity, and actual embedded interest costs. The In-Service Asset Rate Order also included a prudence finding of all costs in the stipulated revenue requirement calculation for the in-service assets. The stipulated revenue requirement excluded the costs of the Kemper IGCC related to the 15% undivided interest that was previously projected to be purchased by SMEPA but reserved the Company's right to seek recovery in a future proceeding. See "Termination of Proposed Sale of Undivided Interest" herein for additional information. The Company is required to file the 2017 Rate Case by June 3, 2017.

With implementation of the new rates on December 17, 2015, the interim rates were terminated and, in March 2016, the Company completed customer refunds of approximately $11 million for the difference between the interim rates collected and the permanent rates.

2013 MPSC Rate Order

In January 2013, the Company entered into a settlement agreement with the Mississippi PSC that was intended to establish the process for resolving matters regarding cost recovery related to the Kemper IGCC (2013 Settlement Agreement). Under the 2013 Settlement Agreement, the Company agreed to limit the portion of prudently-incurred Kemper IGCC costs to be included in retail rate base to the $2.4 billion certificated cost estimate, plus the Cost Cap Exceptions, but excluding AFUDC, and any other costs permitted or determined to be excluded from the $2.88 billion cost cap by the Mississippi PSC. In March 2013, the Mississippi PSC issued a rate order approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014 (2013 MPSC Rate Order) to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service, based on a mirror CWIP methodology (Mirror CWIP rate).

On February 12, 2015, the Court reversed the 2013 MPSC Rate Order based on, among other things, its findings that (1) the Mirror CWIP rate treatment was not provided for under the Baseload Act and (2) the Mississippi PSC should have determined the prudence of Kemper IGCC costs before approving rate recovery through the 2013 MPSC Rate Order. The Court also found the

2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. On July 7, 2015, the Mississippi PSC ordered that the Mirror CWIP rate be terminated effective July 20, 2015 and required the fourth quarter 2015 refund of the $342 million collected under the 2013 MPSC Rate Order, along with associated carrying costs of $29 million . The Court's decision did not impact the 2012 MPSC CPCN Order or the February 2013 legislation described above.

Because the 2013 MPSC Rate Order did not provide for the inclusion of CWIP in rate base as permitted by the Baseload Act, the Company continues to record AFUDC on the Kemper IGCC. Through December 31, 2016, AFUDC recorded since the original May 2014 estimated in-service date for the Kemper IGCC has totaled $398 million , which will continue to accrue at approximately $16 million per month until the remainder of the plant is placed in service. The Company has not recorded any AFUDC on Kemper IGCC costs in excess of the $2.88 billion cost cap, except for Cost Cap Exception amounts.

2012 MPSC CPCN Order

The 2012 MPSC CPCN Order included provisions relating to both the Company's recovery of financing costs during the course of construction of the Kemper IGCC and the Company's recovery of costs following the date the Kemper IGCC is placed in service. With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC CPCN Order provided for the establishment of operational cost and revenue parameters including availability factor, heat rate, lignite heat content, and chemical revenue based upon assumptions in the Company's petition for the CPCN. The Company expects the Mississippi PSC to apply operational parameters in connection with the 2017 Rate Case and future proceedings related to the operation of the Kemper IGCC. To the extent the Mississippi PSC determines the Kemper IGCC does not meet the operational parameters ultimately adopted by the Mississippi PSC or the Company incurs additional costs to satisfy such parameters, there could be a material adverse impact on the Company's financial statements. See "Prudence" herein for additional information.

Regulatory Assets and Liabilities

Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC issued an accounting order in 2011 granting the Company the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset through the in-service date, subject to review of such costs by the Mississippi PSC. Such costs include, but are not limited to, carrying costs on Kemper IGCC assets currently placed in service, costs associated with Mississippi PSC and MPUS consultants, prudence costs, legal fees, and operating expenses associated with assets placed in service.

In August 2014, the Company requested confirmation by the Mississippi PSC of the Company's authority to defer all operating expenses associated with the operation of the combined cycle subject to review of such costs by the Mississippi PSC. In addition, the Company is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings. Beginning in the third quarter 2015 and the second quarter 2016, in connection with the implementation of retail and wholesale rates, respectively, the Company began expensing certain ongoing project costs and certain retail debt carrying costs (associated with assets placed in service and other non-CWIP accounts) that previously were deferred as regulatory assets and began amortizing certain regulatory assets associated with assets placed in service and consulting and legal fees. The amortization periods for these regulatory assets vary from two years to 10 years as set forth in the In-Service Asset Rate Order and the settlement agreement with wholesale customers. As of December 31, 2016, the balance associated with these regulatory assets was $97 million , of which $29 million is included in current assets. Other regulatory assets associated with the remainder of the Kemper IGCC totaled $104 million as of December 31, 2016 . The amortization period for these assets is expected to be determined by the Mississippi PSC in the 2017 Rate Case. See "FERC Matters" herein for additional information related to the 2016 settlement agreement with wholesale customers.

The In-Service Asset Rate Order requires the Company to submit an annual true-up calculation of its actual cost of capital, compared to the stipulated total cost of capital, with the first occurring as of May 31, 2016. At December 31, 2016, the Company's related regulatory liability included in its balance sheet totaled approximately $7 million . See "2015 Rate Case" herein for additional information.

Also see Note 1 under "Regulatory Assets and Liabilities" for additional information.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, the Company owns the lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site. The mine started commercial operation in June 2013.

In 2010, the Company executed a 40 -year management fee contract with Liberty Fuels, which developed, constructed, and is operating and managing the mining operations. The contract with Liberty Fuels is effective through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and the Company has

a contractual obligation to fund all reclamation activities. In addition to the obligation to fund the reclamation activities, the Company currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses. See Note 1 under "Asset Retirement Obligations and Other Costs of Removal" and "Variable Interest Entities" for additional information.

In addition, the Company has constructed and will operate the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. The Company entered into agreements with Denbury Onshore (Denbury) and Treetop Midstream Services, LLC (Treetop), pursuant to which Denbury would purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop would purchase 30% of the CO_2 captured from the Kemper IGCC. On June 3, 2016, the Company cancelled its contract with Treetop and amended its contract with Denbury to reflect, among other things, Denbury's agreement to purchase 100% of the CO_2 captured from the Kemper IGCC, an initial contract term of 16 years, and termination rights if the Company has not satisfied its contractual obligation to deliver captured CO_2 by July 1, 2017, in addition to Denbury's existing termination rights in the event of a change in law, force majeure, or an event of default by the Company. Any termination or material modification of the agreement with Denbury could impact the operations of the Kemper IGCC and result in a material reduction in the Company's revenues to the extent the Company is not able to enter into other similar contractual arrangements or otherwise sequester the CO_2 produced. Additionally, sustained oil price reductions could result in significantly lower revenues than the Company originally forecasted to be available to offset customer rate impacts, which could have a material impact on the Company's financial statements.

The ultimate outcome of these matters cannot be determined at this time.

Termination of Proposed Sale of Undivided Interest

In 2010 and as amended in 2012, the Company and SMEPA entered into an agreement whereby SMEPA agreed to purchase a 15% undivided interest in the Kemper IGCC (15% Undivided Interest). On May 20, 2015, SMEPA notified the Company of its termination of the agreement. The Company previously received a total of $275 million of deposits from SMEPA that were required to be returned to SMEPA with interest. On June 3, 2015, Southern Company, pursuant to its guarantee obligation, returned approximately $301 million to SMEPA. Subsequently, the Company issued a promissory note in the aggregate principal amount of approximately $301 million to Southern Company, which matures on December 1, 2017.

Litigation

On April 26, 2016, a complaint against the Company was filed in Harrison County Circuit Court (Circuit Court) by Biloxi Freezing & Processing Inc., Gulfside Casino Partnership, and John Carlton Dean, which was amended and refiled on July 11, 2016 to include, among other things, Southern Company as a defendant. On August 12, 2016, Southern Company and the Company removed the case to the U.S. District Court for the Southern District of Mississippi. The plaintiffs filed a request to remand the case back to state court, which was granted on November 17, 2016. The individual plaintiff, John Carlton Dean, alleges that the Company and Southern Company violated the Mississippi Unfair Trade Practices Act. All plaintiffs have alleged that the Company and Southern Company concealed, falsely represented, and failed to fully disclose important facts concerning the cost and schedule of the Kemper IGCC and that these alleged breaches have unjustly enriched the Company and Southern Company. The plaintiffs seek unspecified actual damages and punitive damages; ask the Circuit Court to appoint a receiver to oversee, operate, manage, and otherwise control all affairs relating to the Kemper IGCC; ask the Circuit Court to revoke any licenses or certificates authorizing the Company or Southern Company to engage in any business related to the Kemper IGCC in Mississippi; and seek attorney's fees, costs, and interest. The plaintiffs also seek an injunction to prevent any Kemper IGCC costs from being charged to customers through electric rates. On December 7, 2016, Southern Company and the Company filed motions to dismiss.

On June 9, 2016, Treetop, Greenleaf, Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group filed a complaint against the Company, Southern Company, and SCS in the state court in Gwinnett County, Georgia. The complaint relates to the cancelled CO_2 contract with Treetop and alleges fraudulent misrepresentation, fraudulent concealment, civil conspiracy, and breach of contract on the part of the Company, Southern Company, and SCS and seeks compensatory damages of $100 million , as well as unspecified punitive damages. Southern Company, the Company, and SCS have moved to compel arbitration pursuant to the terms of the CO_2 contract.

The Company believes these legal challenges have no merit; however, an adverse outcome in these proceedings could have a material impact on the Company's results of operations, financial condition, and liquidity. The Company will vigorously defend itself in these matters, and the ultimate outcome of these matters cannot be determined at this time.

Baseload Act

In 2008, the Baseload Act was signed by the Governor of Mississippi. The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a

portion of the prudently-incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. See "Rate Recovery of Kemper IGCC Costs" herein for additional information.

Bonus Depreciation

In December 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service through 2020. The PATH Act allows for 50% bonus depreciation for 2015 through 2017, 40% bonus depreciation for 2018, and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. The extension of bonus depreciation included in the PATH Act is expected to result in approximately $20 million of positive cash flows for the 2016 tax year, which was not all realized in 2016 due to a projected consolidated net operating loss (NOL) for Southern Company. Dependent upon placing the remainder of the Kemper IGCC in service by December 31, 2017, the Company expects approximately $370 million of positive cash flows from bonus depreciation for the 2017 tax year, which may not all be realized in 2017 due to additional NOL projections for the 2017 tax year. See " Kemper IGCC Schedule and Cost Estimate " herein and Note 5 under "Current and Deferred Income Taxes – Net Operating Loss" for additional information. The ultimate outcome of this matter cannot be determined at this time.

Investment Tax Credits

The IRS allocated $133 million (Phase I) and $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to the Company in connection with the Kemper IGCC. These tax credits were dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In addition, the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the Internal Revenue Code was also a requirement of the Phase II credits. As a result of schedule extensions for the Kemper IGCC, the Phase I tax credits were recaptured in 2013 and the Phase II tax credits were recaptured in 2015.

Section 174 Research and Experimental Deduction

Southern Company, on behalf of the Company, has reflected deductions for research and experimental (R&E) expenditures related to the Kemper IGCC in its federal income tax calculations since 2013 and has filed amended federal income tax returns for 2008 through 2013 to also include such deductions. The Kemper IGCC is based on first-of-a-kind technology, and Southern Company believes that a significant portion of the plant costs qualify as deductible R&E expenditures under Internal Revenue Code Section 174. In December 2016, Southern Company and the IRS reached a proposed settlement, subject to approval of the U.S. Congress Joint Committee on Taxation, resolving a methodology for these deductions. Due to the uncertainty related to this tax position, the Company had unrecognized tax benefits associated with these R&E deductions totaling approximately $464 million as of December 31, 2016 . See Note 5 under "Unrecognized Tax Benefits" for additional information. This matter is expected to be resolved in the next 12 months; however, the ultimate outcome of this matter cannot be determined at this time.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own, as tenants in common, Units 1 and 2 (total capacity of 500 MWs) at Greene County Steam Plant, which is located in Alabama and operated by Alabama Power. Additionally, the Company and Gulf Power, own as tenants in common, Units 1 and 2 (total capacity of 1,000 MWs) at Plant Daniel, which is located in Mississippi and operated by the Company. At December 31, 2016 , the Company's percentage ownership and investment in these jointly-owned facilities in commercial operation were as follows:

Generating Plant	Company Ownership	Plant in Service	Accumulated Depreciation	CWIP
		(in millions)		
Greene County				
Units 1 and 2	40%	$ 165	$ 48	$ —
Daniel				
Units 1 and 2	50%	$ 695	$ 173	$ 15

The Company's proportionate share of plant operating expenses is included in the statements of operations and the Company is responsible for providing its own financing.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and various combined and separate state income tax returns. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2016	2015	2014
		(in millions)	
Federal —			
Current	**$ (31)**	$ (768)	$ (431)
Deferred	**(60)**	704	183
	(91)	(64)	(248)
State —			
Current	**(6)**	(81)	1
Deferred	**(7)**	73	(38)
	(13)	(8)	(37)
Total	**$ (104)**	$ (72)	$ (285)

NOTES (continued)
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The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2016	2015
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	**$ 386**	$ 1,618
Property basis difference	**852**	—
Regulatory assets associated with AROs	**72**	71
Pensions and other benefits	**49**	30
Regulatory assets associated with employee benefit obligations	**70**	66
Regulatory assets associated with the Kemper IGCC	**82**	86
Rate differential	**144**	115
Other	**125**	176
Total	**1,780**	2,162
Deferred tax assets —		
Fuel clause over recovered	**26**	51
Estimated loss on Kemper IGCC	**484**	451
Pension and other benefits	**96**	92
Federal NOL	**109**	17
Property insurance	**27**	25
Premium on long-term debt	**14**	18
AROs	**72**	71
Property basis difference	**—**	451
Deferred state tax assets	**113**	152
Deferred federal tax assets	**31**	31
Federal effect of state deferred taxes	**19**	8
Other	**33**	33
Total	**1,024**	1,400
Total deferred tax liabilities, net	**756**	762
Accumulated deferred income taxes	**$ 756**	$ 762

The application of bonus depreciation provisions in current tax law significantly increased deferred tax liabilities related to accelerated depreciation.

At December 31, 2016 , the tax-related regulatory assets were $362 million . These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest.

At December 31, 2016 , the tax-related regulatory liabilities were $7 million . These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and unamortized ITCs.

In accordance with regulatory requirements, deferred federal ITCs are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of operations. Credits for non-Kemper IGCC related deferred ITCs amortized in this manner amounted to $1 million in each of 2016, 2015, and 2014.

At December 31, 2016 , the Company had state of Mississippi NOL carryforwards totaling approximately $3 billion , resulting in deferred tax assets of approximately $112 million . The NOLs will expire between 2032 and 2037.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2016	2015	2014
Federal statutory rate	**(35.0)%**	(35.0)%	(35.0)%
State income tax, net of federal deduction	**(5.7)**	(6.3)	(4.0)
Non-deductible book depreciation	**0.7**	1.3	0.1
AFUDC-equity	**(28.5)**	(49.6)	(7.8)
Other	**—**	(2.9)	0.1
Effective income tax rate (benefit rate)	**(68.5)%**	(92.5)%	(46.6)%

The decrease in the Company's 2016 effective tax rate (benefit rate), as compared to 2015, is primarily due to an increase in estimated losses associated with the Kemper IGCC and an increase in non-taxable AFUDC equity. The increase in the Company's 2015 effective tax rate (benefit rate), as compared to 2014, is primarily due to a decrease in estimated losses associated with the Kemper IGCC, partially offset by a decrease in non-taxable AFUDC equity.

On March 30, 2016, the FASB issued ASU 2016-09, which changes the accounting for income taxes for share-based payment award transactions. Entities are required to recognize all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation as income tax expense or benefit in the income statement. The adoption of ASU 2016-09 did not have a material impact on the Company's overall effective tax rate. See Note 1 under "Recently Issued Accounting Standards" for additional information.

Unrecognized Tax Benefits

Changes during the year in unrecognized tax benefits were as follows:

	2016	2015	2014
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 421**	$ 165	$ 4
Tax positions increase from current periods	**26**	32	58
Tax positions increase from prior periods	**18**	224	103
Balance at end of year	**$ 465**	$ 421	$ 165

The tax positions increases from current periods and prior periods for 2016, 2015 and 2014 relate to deductions for R&E expenditures associated with the Kemper IGCC. See "Section 174 Research and Experimental Deduction" herein for additional information.

The impact on the Company's effective tax rate, if recognized, is as follows:

	2016	2015	2014
		(in millions)	
Tax positions impacting the effective tax rate	**$ 1**	$ (2)	$ 4
Tax positions not impacting the effective tax rate	**464**	423	161
Balance of unrecognized tax benefits	**$ 465**	$ 421	$ 165

The tax positions not impacting the effective tax rate relate to deductions for R&E expenditures associated with the Kemper IGCC. See "Section 174 Research and Experimental Deduction" herein for additional information.

Accrued interest for unrecognized tax benefits was as follows:

	2016	2015	2014
		(in millions)	
Interest accrued at beginning of year	**$ 13**	$ 3	$ 1
Interest accrued during the year	**15**	10	2
Balance at end of year	**$ 28**	$ 13	$ 3

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months . The settlement of federal and state audits and U.S. Congress Joint Committee on Taxation approval of the R&E expenditures associated with the Kemper IGCC could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined. See "Section 174 Research and Experimental Deduction" herein for additional information.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013, 2014, and 2015 federal income tax returns and has received partial acceptance letters from the IRS; however, the IRS has not finalized its audits. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

Section 174 Research and Experimental Deduction

Southern Company, on behalf of the Company, reflected deductions for R&E expenditures related to the Kemper IGCC in its federal income tax calculations since 2013 and filed amended federal income tax returns for 2008 through 2013 to also include such deductions.

The Kemper IGCC is based on first-of-a-kind technology, and Southern Company and the Company believe that a significant portion of the plant costs qualify as deductible R&E expenditures under Internal Revenue Code Section 174. In December 2016, Southern Company and the IRS reached a proposed settlement, subject to approval of the U.S. Congress Joint Committee on Taxation, resolving a methodology for these deductions. Due to the uncertainty related to this tax position, the Company had unrecognized tax benefits associated with these R&E deductions totaling approximately $464 million and associated interest of $28 million as of December 31, 2016. This matter is expected to be resolved in the next 12 months; however, the ultimate outcome of this matter cannot be determined at this time. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

6. FINANCING

Going Concern

As of December 31, 2016, the Company's current liabilities exceeded current assets by approximately $371 million primarily due to $551 million in promissory notes to Southern Company which mature in December 2017, $35 million in senior notes which mature in November 2017, and $63 million in short-term debt. The Company expects the funds needed to satisfy the promissory notes to Southern Company will exceed amounts available from operating cash flows, lines of credit, and other external sources. Accordingly, the Company intends to satisfy these obligations through loans and/or equity contributions from Southern Company. Specifically, the Company has been informed by Southern Company that, in the event sufficient funds are not available from external sources, Southern Company intends to (i) extend the maturity of the $551 million in promissory notes and (ii) provide Mississippi Power with loans and/or equity contributions sufficient to fund the remaining indebtedness scheduled to mature and other cash needs over the next 12 months. Therefore, the Company's financial statement presentation contemplates continuation of the Company as a going concern as a result of Southern Company's anticipated ongoing financial support of the Company, consistent with the requirements of ASU 2014-15. See Note 1 under "Recently Issued Accounting Standards" for additional information regarding ASU 2014-15.

Parent Company Loans and Equity Contributions

On January 28, 2016, the Company issued a promissory note for up to $275 million to Southern Company, which matures in December 2017, bearing interest based on one-month LIBOR. During 2016, the Company borrowed $100 million under this promissory note and an additional $100 million under a separate promissory note issued to Southern Company in November 2015.

On June 27, 2016, the Company received a capital contribution from Southern Company of $225 million , the proceeds of which were used to repay to Southern Company a portion of the promissory note issued in November 2015. Also, on December 14, 2016, the Company received a capital contribution from Southern Company of $400 million , the proceeds of which were used for general corporate purposes. As of December 31, 2016 and 2015, the amount of outstanding promissory notes to Southern Company totaled $551 million and $576 million , respectively.

Bank Term Loans

In March 2016, the Company entered into an unsecured term loan agreement with a syndicate of financial institutions for an aggregate amount of $1.2 billion . The Company borrowed $900 million in March 2016 under the term loan agreement and the remaining $300 million in October 2016. The Company used the initial proceeds to repay $900 million in maturing bank loans in March 2016 and the remaining $300 million to repay at maturity the Company's Series 2011A 2.35% Senior Notes due October 15, 2016. The term loan pursuant to this agreement matures on April 1, 2018 and bears interest based on one-month LIBOR.

This bank loan has a covenant that limits debt levels to 65% of total capitalization, as defined in the agreement. For purposes of this definition, debt excludes any long-term debt payable to affiliated trusts, other hybrid securities, and any securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2016 , the Company was in compliance with its debt limit.

At December 31, 2016 , the Company had a total of $1.2 billion in bank loans outstanding. At December 31, 2015, the Company had a total of $900 million in bank loans outstanding, including $475 million classified as notes payable and $425 million classified as securities due within one year.

Senior Notes

At December 31, 2016 and 2015 , the Company had $790 million and $1.1 billion of senior notes outstanding, respectively, which included senior notes due within one year. These senior notes are effectively subordinated to the secured debt of the Company. See "Plant Daniel Revenue Bonds" below for additional information regarding the Company's secured indebtedness.

Plant Daniel Revenue Bonds

In 2011, in connection with the Company's election under its operating lease of Plant Daniel Units 3 and 4 to purchase the assets, the Company assumed the obligations of the lessor related to $270 million aggregate principal amount of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 20, 2021, issued for the benefit of the lessor. These bonds are secured by Plant Daniel Units 3 and 4 and certain related personal property. The bonds were recorded at fair value as of the date of assumption, or $346 million , reflecting a premium of $76 million . See "Assets Subject to Lien" herein for additional information.

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31, 2016 and 2015 was as follows:

	2016	**2015**
	(in millions)	
Parent company loans	**$ 551**	$ —
Senior notes	**35**	300
Bank term loans	**—**	425
Pollution control revenue bonds [(*)]	**40**	—
Capitalized leases	**3**	3
Outstanding at December 31	**$ 629**	$ 728

(*) Pollution control revenue bonds are classified as short term since they are variable rate demand obligations that are supported by short-term credit facilities; however, the final maturity date is in 2028.

Maturities through 2021 applicable to total long-term debt are as follows: $629 million in 2017, $1.2 billion in 2018, $128 million in 2019, $10 million in 2020, and $274 million in 2021.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of pollution control revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2016 and 2015 was $83 million .

Other Revenue Bonds

Other revenue bond obligations represent loans to the Company from a public authority of funds derived from the sale by such authority of revenue bonds issued to finance a portion of the costs of constructing the Kemper IGCC and related facilities.

The Company had $50 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2016 and 2015 . Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.

Capital Leases

In 2013, the Company entered into an agreement to sell the air separation unit for the Kemper IGCC and also entered into a 20 -year nitrogen supply agreement. The nitrogen supply agreement was determined to be a sale/leaseback agreement which resulted in a capital lease obligation at December 31, 2016 and 2015 of $74 million and $77 million , respectively, with an annual interest rate of 4.9% for both years. There are no contingent rentals in the contract and a portion of the monthly payment specified in the agreement is related to executory costs for the operation and maintenance of the air separation unit and excluded from the minimum lease payments. The minimum lease payments for 2016 were $7 million and will be $7 million each year thereafter. Amortization of the capital lease asset for the air separation unit will begin when the Kemper IGCC is placed in service. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

Assets Subject to Lien

The revenue bonds assumed in conjunction with the purchase of Plant Daniel Units 3 and 4 are secured by Plant Daniel Units 3 and 4 and certain related personal property. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy the obligations of Southern Company or another of its other subsidiaries. See "Plant Daniel Revenue Bonds" herein for additional information.

Outstanding Classes of Capital Stock

The Company currently has preferred stock (including depositary shares which represent one-fourth of a share of preferred stock) and common stock authorized and outstanding. The preferred stock of the Company contains a feature that allows the holders to elect a majority of the Company's board of directors if preferred dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of the Company, this preferred stock is presented as "Cumulative Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards. The Company's preferred stock and depositary preferred stock, without preference between classes, rank senior to the Company's common stock with respect to payment of dividends and voluntary or involuntary dissolution. The preferred stock and depositary preferred stock is subject to redemption at the option of the Company at a redemption price equal to 100% of the liquidation amount of the stock. Information for each outstanding series is in the table below:

Preferred Stock	Par Value/Stated Capital Per Share	Shares Outstanding	Redemption Price Per Share
4.40% Preferred Stock	$ 100	8,867	$ 104.32
4.60% Preferred Stock	$ 100	8,643	$ 107.00
4.72% Preferred Stock	$ 100	16,700	$ 102.25
5.25% Preferred Stock (*)	$ 100	300,000	$ 100.00

(*) There are 1,200,000 outstanding depositary shares, each representing one-fourth of a share of the 5.25% preferred stock.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Bank Credit Arrangements

At December 31, 2016 , committed credit arrangements with banks were as follows:

Expires			Executable Term Loans		Expires Within One Year	
2017	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)	*(in millions)*		*(in millions)*		*(in millions)*	
$173	$173	$150	$—	$13	$13	$160

Subject to applicable market conditions, the Company expects to renew its bank credit arrangements, as needed, prior to expiration. In connection therewith, the Company may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

Most of these bank credit arrangements require payment of commitment fees based on the unused portions of the commitments or to maintain compensating balances with the banks. Commitment fees average less than 1/4 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

Most of these bank credit arrangements contain covenants that limit the Company's debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes certain hybrid securities and any securitized debt relating to the securitization of certain costs of the Kemper IGCC.

A portion of the $150 million unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and its commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2016 was $40 million .

At December 31, 2016 and 2015 , there was no commercial paper debt outstanding.

At December 31, 2016 and 2015 , there was $23 million and $500 million , respectively, of short-term debt outstanding.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil fuel which are not recognized on the balance sheets. In 2016 , 2015 , and 2014 , the Company incurred fuel expense of $343 million , $443 million , and $574 million , respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

Coal commitments include a management fee associated with a 40 -year management contract with Liberty Fuels related to the Kemper IGCC with the remaining amount as of December 31, 2016 of $41 million . Additional commitments for fuel will be required to supply the Company's future needs.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional electric operating companies and Southern Power. Under these agreements, each of the traditional electric operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional electric operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total rent expense was $3 million , $5 million , and $10 million for 2016 , 2015 , and 2014 , respectively.

The Company and Gulf Power have jointly entered into operating lease agreements for aluminum railcars for the transportation of coal at Plant Daniel. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value or to renew the leases at the end of the lease term. The Company has one remaining operating lease which has 229 aluminum railcars. The Company and Gulf Power also have separate lease agreements for other railcars that do not contain a purchase option.

The Company's 50% share of the lease costs, charged to fuel stock and recovered through the fuel cost recovery clause, was $2 million in 2016 , $2 million in 2015 , and $3 million in 2014 . The Company's annual railcar lease payments for 2017 will be approximately $1 million . Lease obligations for the period 2018 and thereafter are immaterial.

In addition to railcar leases, the Company has other operating leases for fuel handling equipment at Plant Daniel. The Company's 50% share of the leases for fuel handling was charged to fuel handling expense annually from 2014 through 2016 ; however, those amounts were immaterial for the reporting period. The Company's annual lease payments through 2020 are expected to be immaterial for fuel handling equipment.

8. STOCK COMPENSATION

Stock-Based Compensation

Stock-based compensation primarily in the form of Southern Company performance share units may be granted through the Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2016 , there were 220 current and former employees participating in the stock option and performance share unit programs.

Stock Options

Through 2009, stock-based compensation granted to employees consisted exclusively of non-qualified stock options. The exercise price for stock options granted equaled the stock price of Southern Company common stock on the date of grant. Stock options vest on a pro rata basis over a maximum period of three years from the date of grant or immediately upon the retirement or death of the employee. Options expire no later than 10 years after the grant date. All unvested stock options vest immediately upon a change in control where Southern Company is not the surviving corporation. Compensation expense is generally recognized on a straight-line basis over the three -year vesting period with the exception of employees that are retirement eligible at the grant date and employees that will become retirement eligible during the vesting period. Compensation expense in those instances is recognized at the grant date for employees that are retirement eligible and through the date of retirement eligibility for those employees that become retirement eligible during the vesting period. In 2015, Southern Company discontinued the granting of stock options.

The weighted average grant-date fair value of stock options granted during 2014 derived using the Black-Scholes stock option pricing model was $2.20 .

The compensation cost related to the grant of Southern Company stock options to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. Compensation cost and related tax benefits recognized in the Company's financial statements were not material for any year presented. As of December 31, 2016 , the amount of unrecognized compensation cost related to stock option awards not yet vested was immaterial.

The total intrinsic value of options exercised during the years ended December 31, 2016 , 2015 , and 2014 was $4 million , $3 million , and $5 million , respectively. No cash proceeds are received by the Company upon the exercise of stock options. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $2 million , $1 million , and $2 million for the years ended December 31, 2016 , 2015 , and 2014 , respectively. Prior to the adoption of ASU 2016-09, the excess tax benefits related to the exercise of stock options were recognized in the Company's financial statements with a credit to equity. Upon the adoption of ASU 2016-09, beginning in 2016, all tax benefits related to the exercise of stock options are recognized in income. As of December 31, 2016 , the aggregate intrinsic value for the options outstanding and options exercisable was $6 million and $5 million , respectively.

Performance Share Units

From 2010 through 2014, stock-based compensation granted to employees included performance share units in addition to stock options. Beginning in 2015, stock-based compensation consisted exclusively of performance share units. Performance share units granted to employees vest at the end of a three -year performance period. All unvested performance share units vest immediately upon a change in control where Southern Company is not the surviving corporation. Shares of Southern Company common stock are delivered to employees at the end of the performance period with the number of shares issued ranging from 0% to 200% of the target number of performance share units granted, based on achievement of the performance goals established by the Compensation Committee of the Southern Company Board of Directors.

The performance goal for all performance share units issued from 2010 through 2014 was based on the total shareholder return (TSR) for Southern Company common stock during the three -year performance period as compared to a group of industry peers.

For these performance share units, at the end of three years , active employees receive shares based on Southern Company's performance while retired employees receive a pro rata number of shares based on the actual months of service during the performance period prior to retirement. The fair value of TSR-based performance share unit awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's common stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three -year performance period without remeasurement.

Beginning in 2015, Southern Company issued two additional types of performance share units to employees in addition to the TSR-based awards. These included performance share units with performance goals based on cumulative earnings per share (EPS) over the performance period and performance share units with performance goals based on Southern Company's equity-weighted ROE over the performance period. The EPS-based and ROE-based awards each represent 25% of total target grant date fair value of the performance share unit awards granted. The remaining 50% of the target grant date fair value consists of TSR-based awards. In contrast to the Monte Carlo simulation model used to determine the fair value of the TSR-based awards, the fair values of the EPS-based awards and the ROE-based awards are based on the closing stock price of Southern Company common stock on the date of the grant. Compensation expense for the EPS-based and ROE-based awards is generally recognized ratably over the three -year performance period initially assuming a 100% payout at the end of the performance period. The TSR-based performance share units, along with the EPS-based and ROE-based awards, vest immediately upon the retirement of the employee. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately while compensation expense for employees that become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility. The expected payout related to the EPS-based and ROE-based awards is reevaluated annually with expense recognized to date increased or decreased based on the number of shares currently expected to be issued. Unlike the TSR-based awards, the compensation expense ultimately recognized for the EPS-based awards and the ROE-based awards will be based on the actual number of shares issued at the end of the performance period.

For the years ended December 31, 2016 , 2015 , and 2014 , employees of the Company were granted performance share units of 62,435 , 53,909 , and 49,579 , respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2016 , 2015 , and 2014 , determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $45.17 , $46.41 , and $37.54 , respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2016 and 2015 was $48.84 and $47.77 , respectively.

For the years ended December 31, 2016 , 2015 , and 2014 , total compensation cost for performance share units recognized in income was $4 million , $4 million , and $2 million , respectively, with the related tax benefit also recognized in income of $1 million , $2 million , and $1 million , respectively. The compensation cost related to the grant of Southern Company performance share units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2016 , $1 million of total unrecognized compensation cost related to performance share award units will be recognized over a weighted-average period of approximately 22 months .

9. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2016 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

	Fair Value Measurements Using			
As of December 31, 2016:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Energy-related derivatives	$ —	$ 3	$ —	$ 3
Interest rate derivatives	—	3	—	3
Cash equivalents	206	—	—	206
Total	$ 206	$ 6	$ —	$ 212
Liabilities:				
Energy-related derivatives	$ —	$ 10	$ —	$ 10

As of December 31, 2015 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

	Fair Value Measurements Using			
As of December 31, 2015:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Cash equivalents	$ 52	$ —	$ —	$ 52
Liabilities:				
Energy-related derivatives	$ —	$ 47	$ —	$ 47

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Foreign currency derivatives are also standard over-the-counter financial products valued using the market approach. Inputs for foreign currency derivatives are from observable market sources. See Note 10 for additional information on how these derivatives are used.

As of December 31, 2016 and 2015 , other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2016	**$ 2,979**	**$ 2,922**
2015	$ 2,537	$ 2,413

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to the Company.

10. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net basis. See Note 9 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in energy-related commodity prices. The Company manages fuel-hedging programs, implemented per the guidelines of the Mississippi PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

Energy-related derivative contracts are accounted for under one of the following methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the respective fuel cost recovery clauses.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of operations as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2016 , the net volume of energy-related derivative contracts for natural gas positions totaled 36 million mmBtu for the Company, with the longest hedge date of 2020 over which the Company is hedging its exposure to the variability in future cash flows for forecasted transactions.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to income.

At December 31, 2016 , the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2016
	(in millions)				*(in millions)*
Cash Flow Hedges of Existing Debt	$ 900	1-month LIBOR	0.79%	March 2018	$ 3

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the next 12-month period ending December 31, 2017 are $2 million . The Company has deferred gains and losses that are expected to be amortized into earnings through 2022 .

Derivative Financial Statement Presentation and Amounts

The Company enters into energy-related and interest rate derivative contracts that may contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. At December 31, 2016 , fair value amounts of derivative assets and liabilities on the balance sheets are presented net to the extent that there are netting arrangements or similar agreements with counterparties. At December 31, 2015 , the fair value amounts of derivative instruments were presented gross on the balance sheets.

At December 31, 2016 and 2015 , the fair value of energy-related derivatives and interest rate derivatives was reflected on the balance sheets as follows:

	2016		2015	
Derivative Category and Balance Sheet Location	**Assets**	**Liabilities**	Assets	Liabilities
		(in millions)		
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Other current liabilities	**$ 2**	**$ 6**	$ —	$ 29
Other deferred charges and assets/Other deferred credits and liabilities	**2**	**5**	—	18
Total derivatives designated as hedging instruments for regulatory purposes	**$ 4**	**$ 11**	$ —	$ 47
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Interest rate derivatives:				
Other current assets/Other current liabilities	**$ 2**	**$ —**	$ —	$ —
Other deferred charges and assets/Other deferred credits and liabilities	**1**	**—**	—	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges	**$ 3**	**$ —**	$ —	$ —
Gross amounts recognized	**$ 7**	**$ 11**	$ —	$ 47
Gross amounts offset	**$ (3)**	**$ (3)**	$ —	$ —
Net amounts recognized in the Balance Sheets (*)	**$ 4**	**$ 8**	$ —	$ 47

(*) At December 31, 2015 , the fair value amounts for derivative contracts subject to netting arrangements were presented gross on the balance sheet.

Energy-related derivatives not designated as hedging instruments were immaterial for 2016 and 2015 .

At December 31, 2016 and 2015 , the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivatives designated as regulatory hedging instruments and deferred were as follows:

	Unrealized Losses			**Unrealized Gains**		
Derivative Category	**Balance Sheet Location**	**2016**	2015	**Balance Sheet Location**	**2016**	2015
		(in millions)			*(in millions)*	
Energy-related derivatives: (*)	Other regulatory assets, current	**$ (5)**	$ (29)	Other regulatory liabilities, current	**$ 1**	$ —
	Other regulatory assets, deferred	**(3)**	(18)	Other regulatory liabilities, deferred	**—**	—
Total energy-related derivative gains (losses)		**$ (8)**	$ (47)		**$ 1**	$ —

(*) At December 31, 2016 , the unrealized gains and losses for derivative contracts subject to netting arrangements were presented net on the balance sheet. At December 31, 2015 , the unrealized gains and losses for derivative contracts were presented gross on the balance sheet.

For all years presented, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of operations were immaterial.

For the year ended December 31, 2016, the pre-tax effects of derivatives designated as cash flow hedging instruments on the statements of operations were $3 million . For the years ended December 31, 2015 and 2014, these effects were immaterial.

There was no material ineffectiveness recorded in earnings for any period presented.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2016 , the Company's collateral posted with its derivative counterparties was immaterial.

At December 31, 2016 , the fair value of derivative liabilities with contingent features, including certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade because of joint and several liability features underlying these derivatives, was immaterial.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2016 and 2015 is as follows:

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss) After Dividends on Preferred Stock
		(in millions)	
March 2016	**$ 257**	**$ (10)**	**$ 11**
June 2016	**277**	**(28)**	**2**
September 2016	**352**	**9**	**26**
December 2016	**277**	**(166)**	**(89)**
March 2015	$ 276	$ 24	$ 35
June 2015	275	12	49
September 2015	341	(66)	(21)
December 2015	246	(143)	(71)

In accordance with the adoption of ASU 2016-09 (see Note 1 under "Recently Issued Accounting Standards"), previously reported amounts for income tax expense were reduced by $1 million in 2016.

As a result of the revisions to the cost estimate for the Kemper IGCC, the Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC of $206 million ($127 million after tax) in the fourth quarter 2016, $88 million ($54 million after tax) in the third quarter 2016, $81 million ($50 million after tax) in the second quarter 2016, $53 million ($33 million after tax) in the first quarter 2016, $183 million ($113 million after tax) in the fourth quarter 2015, $150 million ($93 million after tax) in the third quarter 2015, $23 million ($14 million after tax) in the second quarter 2015, and $9 million ($6 million after tax) in the first quarter 2015. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

The Company's business is influenced by seasonal weather conditions.

SELECTED FINANCIAL AND OPERATING DATA 2012 - 2016
Mississippi Power Company 2016 Annual Report

	2016	2015	2014	2013	2012
Operating Revenues (in millions)	**$ 1,163**	$ 1,138	$ 1,243	$ 1,145	$ 1,036
Net Income (Loss) After Dividends on Preferred Stock (in millions)	**$ (50)**	$ (8)	$ (329)	$ (477)	$ 100
Cash Dividends on Common Stock (in millions)	**$ —**	$ —	$ —	$ 72	$ 107
Return on Average Common Equity (percent)	**(1.87)**	(0.34)	(15.43)	(24.28)	7.14
Total Assets (in millions) [(a)(b)]	**$ 8,235**	$ 7,840	$ 6,642	$ 5,822	$ 5,334
Gross Property Additions (in millions)	**$ 946**	$ 972	$ 1,389	$ 1,773	$ 1,665
Capitalization (in millions):					
Common stock equity	**$ 2,943**	$ 2,359	$ 2,084	$ 2,177	$ 1,749
Redeemable preferred stock	**33**	33	33	33	33
Long-term debt [(a)]	**2,424**	1,886	1,621	2,157	1,561
Total (excluding amounts due within one year)	**$ 5,400**	$ 4,278	$ 3,738	$ 4,367	$ 3,343
Capitalization Ratios (percent):					
Common stock equity	**54.5**	55.1	55.8	49.9	52.3
Redeemable preferred stock	**0.6**	0.8	0.9	0.7	1.0
Long-term debt [(a)]	**44.9**	44.1	43.3	49.4	46.7
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**153,172**	153,158	152,453	152,585	152,265
Commercial	**33,783**	33,663	33,496	33,250	33,112
Industrial	**451**	467	482	480	472
Other	**175**	175	175	175	175
Total	**187,581**	187,463	186,606	186,490	186,024
Employees (year-end)	**1,484**	1,478	1,478	1,344	1,281

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $9 million, $11 million, and $4 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(b) A reclassification of deferred tax assets from Total Assets of $105 million, $16 million, and $36 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

SELECTED FINANCIAL AND OPERATING DATA 2012 - 2016 (continued)
Mississippi Power Company 2016 Annual Report

	2016	2015	2014	2013	2012
Operating Revenues (in millions):					
Residential	$ 260	$ 238	$ 239	$ 242	$ 227
Commercial	279	256	257	266	251
Industrial	313	287	291	289	263
Other	7	(5)	8	2	6
Total retail	859	776	795	799	747
Wholesale — non-affiliates	261	270	323	294	256
Wholesale — affiliates	26	76	107	35	16
Total revenues from sales of electricity	1,146	1,122	1,225	1,128	1,019
Other revenues	17	16	18	17	17
Total	$ 1,163	$ 1,138	$ 1,243	$ 1,145	$ 1,036
Kilowatt-Hour Sales (in millions):					
Residential	2,051	2,025	2,126	2,088	2,046
Commercial	2,842	2,806	2,860	2,865	2,916
Industrial	4,906	4,958	4,943	4,739	4,702
Other	39	40	40	40	38
Total retail	9,838	9,829	9,969	9,732	9,702
Wholesale — non-affiliates	3,920	3,852	4,191	3,929	3,819
Wholesale — affiliates	1,108	2,807	2,900	931	572
Total	14,866	16,488	17,060	14,592	14,093
Average Revenue Per Kilowatt-Hour (cents) (*) :					
Residential	12.68	11.75	11.26	11.59	11.09
Commercial	9.82	9.12	8.99	9.27	8.60
Industrial	6.38	5.79	5.89	6.10	5.59
Total retail	8.73	7.90	7.97	8.21	7.70
Wholesale	5.71	5.20	6.06	6.76	6.19
Total sales	7.71	6.80	7.18	7.73	7.23
Residential Average Annual Kilowatt-Hour Use Per Customer	13,383	13,242	13,934	13,680	13,426
Residential Average Annual Revenue Per Customer	$ 1,697	$ 1,556	$ 1,568	$ 1,585	$ 1,489
Plant Nameplate Capacity Ratings (year-end) (megawatts)	3,481	3,561	3,867	3,088	3,088
Maximum Peak-Hour Demand (megawatts):					
Winter	2,195	2,548	2,618	2,083	2,168
Summer	2,384	2,403	2,345	2,352	2,435
Annual Load Factor (percent)	64.0	60.6	59.4	64.7	61.9
Plant Availability Fossil-Steam (percent)	91.4	90.6	87.6	89.3	91.5
Source of Energy Supply (percent):					
Coal	8.0	16.5	39.7	32.7	22.8
Oil and gas	84.9	81.6	55.3	57.1	63.9
Purchased power —					
From non-affiliates	(0.3)	0.4	1.4	2.0	2.0
From affiliates	7.4	1.5	3.6	8.2	11.3
Total	100.0	100.0	100.0	100.0	100.0

(*) The average revenue per kilowatt-hour (cents) is based on booked operating revenues and will not match billed revenue per kilowatt-hour.

SOUTHERN POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Southern Power Company and Subsidiary Companies 2016 Annual Report

The management of Southern Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2016 .

/s/ Joseph A. Miller
Joseph A. Miller
Chairman, President, and Chief Executive Officer

/s/ William C. Grantham
William C. Grantham
Senior Vice President, Chief Financial Officer, and Treasurer

February 21, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Southern Power Company

We have audited the accompanying consolidated balance sheets of Southern Power Company and Subsidiary Companies (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2016 and 2015 , and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2016 . These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements (pages II-507 to II-536) present fairly, in all material respects, the financial position of Southern Power Company and Subsidiary Companies as of December 31, 2016 and 2015 , and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 , in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 21, 2017

DEFINITIONS

Term	Meaning
Alabama Power	Alabama Power Company
AOCI	Accumulated other comprehensive income
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
COD	Commercial operation date
CWIP	Construction work in progress
EMC	Electric Membership Corporation
EPA	U.S. Environmental Protection Agency
EPE	El Paso Electric Company
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
First Solar	First Solar, Inc.
FPL	Florida Power & Light Company
GAAP	U.S. generally accepted accounting principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
Invenergy	Invenergy Wind Global LLC
IRS	Internal Revenue Service
ITC	Investment tax credit
KWH	Kilowatt-hour
LTSA	Long-term service agreement
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
MWH	Megawatt hour
OCI	Other comprehensive income
power pool	The operating arrangement whereby the integrated generating resources of the traditional 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 agreements and contracts for differences that provide the owner of a renewable facility a certain fixed price for the electricity sold to the grid
PTC	Production tax credit
Recurrent	Recurrent Energy, LLC
S&P	S&P Global Ratings, a division of S&P Global Inc.
SCE	Southern California Edison Company
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
Southern Company	The Southern Company
Southern Company Gas	Southern Company Gas (formerly known as AGL Resources Inc.) and its subsidiaries
Southern Company system	Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas (as of July 1, 2016), Southern Electric Generating Company, Southern Nuclear, SCS, Southern LINC, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries
Southern LINC	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.

DEFINITIONS
(continued)

Term	Meaning
SRE	Southern Renewable Energy, Inc. owned 100% by Southern Power Company
SRP	Southern Renewable Partnerships, LLC owned 100% by Southern Power Company
STR	Southern Turner Renewable Energy, LLC owned 90% by SRE and 10% by TRE
SunPower	SunPower Corp.
traditional electric operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power
TRE	Turner Renewable Energy, LLC, a 10% partner with SRE

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Southern Power Company and Subsidiary Companies 2016 Annual Report

OVERVIEW

Business Activities

Southern Power Company and its subsidiaries (the Company) construct, acquire, own, and manage power generation assets, including renewable energy projects, and sell electricity at market-based rates in the wholesale market. The Company continually seeks opportunities to execute its strategy to create value through various transactions including acquisitions and sales of assets, construction of new generating facilities, and entry into PPAs primarily with investor-owned utilities, independent power producers, municipalities, and other load-serving entities. In general, the Company has constructed or acquired new generating capacity only after entering into or assuming long-term PPAs for the new facilities.

During 2016 , the Company acquired or commenced construction of approximately 2,134 MWs of additional solar, wind, and natural gas facilities and completed construction of approximately 1,060 MWs of solar facilities. In addition, the Company entered into a joint development agreement to develop and construct up to approximately 3,000 MWs of wind facilities to be placed in service between 2018 and 2020. Subsequent to December 31, 2016 , the Company acquired Bethel Wind, LLC (Bethel Wind), which is an approximately 276-MW wind facility. See FUTURE EARNINGS POTENTIAL – "Acquisitions" and "Construction Projects" herein for additional information.

As of December 31, 2016 , the Company owned generating units totaling 11,768 MWs of nameplate capacity in commercial operation (including 3,980 MWs owned by its subsidiaries), after taking into consideration its equity ownership percentage of the solar and wind facilities. The average remaining duration of the Company's total portfolio of wholesale contracts is approximately 16 years, which reduces remarketing risk for the Company. With the inclusion of the PPAs and investments associated with the solar and natural gas facilities currently under construction and Bethel Wind, which was acquired subsequent to December 31, 2016, as well as other capacity and energy contracts, the Company has an average investment coverage ratio of 91% through 2021 and 90% through 2026.

The Company's future earnings will also depend on the parameters of the wholesale market and the efficient operation of its wholesale generating assets. The Company's renewable energy projects may be impacted by the availability of federal and state solar ITCs and wind PTCs, which could be impacted by potential tax reform legislation. See FUTURE EARNINGS POTENTIAL – "Acquisitions," "Construction Projects," and "Income Tax Matters – Tax Credits" herein for additional information.

To evaluate operating results and to ensure the Company's ability to meet its contractual commitments to customers, the Company continues to focus on several key performance indicators, including, but not limited to, peak season equivalent forced outage rate and contract availability.

See RESULTS OF OPERATIONS herein for information on the Company's financial performance.

Earnings

The Company's 2016 net income was $338 million , a $123 million, or 57%, increase from 2015 . The increase was primarily due to increased federal income tax benefits from solar ITCs and wind PTCs and increased renewable energy sales, partially offset by increases in depreciation, operations and maintenance expenses, and interest expense from debt issuances, primarily related to new solar and wind facilities.

The Company's 2015 net income was $215 million , a $43 million, or 25%, increase from 2014 . The increase was primarily due to increased revenues from new PPAs, including solar and wind, partially offset by increased depreciation and other operations and maintenance expenses primarily due to new solar and wind facilities and higher income taxes.

Benefits from solar ITCs, related to the Company's acquisition and construction of new facilities, and wind PTCs, related to wind generation, significantly impacted the Company's net income in 2016. The Company's net income in 2015 and 2014 was also significantly impacted by solar ITCs. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2016	**2016**	2015
		(in millions)	
Operating revenues	**$ 1,577**	**$ 187**	$ (111)
Fuel	**456**	**15**	(155)
Purchased power	**102**	**9**	(78)
Other operations and maintenance	**354**	**94**	23
Depreciation and amortization	**352**	**104**	28
Taxes other than income taxes	**23**	**1**	—
Total operating expenses	**1,287**	**223**	(182)
Operating income	**290**	**(36)**	71
Interest expense, net of amounts capitalized	**117**	**40**	(12)
Other income (expense), net	**6**	**5**	(5)
Income taxes (benefit)	**(195)**	**(216)**	24
Net income	**374**	**145**	54
Less: Net income attributable to noncontrolling interests	**36**	**22**	11
Net income attributable to the Company	**$ 338**	**$ 123**	$ 43

Operating Revenues

Total operating revenues include PPA capacity revenues, which are derived primarily from long-term contracts involving natural gas and biomass generating facilities, and PPA energy revenues which include sales from the Company's natural gas, biomass, solar, and wind facilities. To the extent the Company has capacity not contracted under a PPA, it may sell power into the wholesale market or the Company (excluding its subsidiaries) may sell power into the power pool.

Natural Gas and Biomass Capacity and Energy Revenue:

- Capacity revenues generally represent the greatest contribution to net income and are designed to provide recovery of fixed costs plus a return on investment.
- Energy is generally sold at variable cost or is indexed to published gas indices. Energy revenues will vary depending on the energy demand of the Company's customers and their generation capacity, as well as the market prices of wholesale energy compared to the cost of the Company's energy. Energy revenues also include fees for support services, fuel storage, and unit start charges. Increases and decreases in energy revenues under PPAs that are driven by fuel or purchased power prices are accompanied by an increase or decrease in fuel and purchased power costs and do not have a significant impact on net income.

Solar and Wind Energy Revenue:

- The Company's electricity sales from solar and wind generating facilities are predominantly through long-term PPAs; however, these solar and wind PPAs do not have a capacity charge and customers either purchase the energy output of a dedicated renewable facility through an energy charge or pay a fixed price for electricity sold to the grid. As a result, the Company's ability to recover fixed and variable operations and maintenance expenses is dependent upon the level of energy generated from these facilities, which can be impacted by weather conditions, equipment performance, and other factors.

See FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" herein for additional information regarding the Company's PPAs.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Details of the Company's operating revenues were as follows:

	2016	2015	2014
		(in millions)	
PPA capacity revenues	$ 541	$ 569	$ 546
PPA energy revenues	694	560	638
Total PPA revenues	1,235	1,129	1,184
Non-PPA revenues	330	252	315
Other revenues	12	9	2
Total operating revenues	$ 1,577	$ 1,390	$ 1,501

Operating revenues for 2016 were $1.6 billion , reflecting a $187 million , or 13%, increase from 2015 . The increase in operating revenues was primarily due to the following:

- PPA capacity revenues decreased $28 million as a result of a $44 million decrease in non-affiliate capacity revenues primarily as a result of PPA expirations and subsequent generation capacity remarketing into the short-term markets, partially offset by a $16 million increase in affiliate capacity revenues due to new PPAs.
- PPA energy revenues increased $134 million primarily due to a $170 million increase in renewable energy sales arising from new solar and wind facilities, partially offset by a decrease of $36 million in fuel revenues related to PPAs served by natural gas facilities. Overall, total KWH sales under PPAs increased 7% in 2016 when compared to 2015.
- Non-PPA revenues increased $78 million primarily due to a 23% increase in KWH sales. Underlying this increase was a $113 million increase in short-term sales to non-affiliates as a result of remarketing generation capacity from expired PPAs, partially offset by a $35 million decrease in power pool sales primarily associated with a reduction in capacity available for sale.

Operating revenues for 2015 were $1.4 billion, reflecting a $111 million, or 7%, decrease from 2014 . The decrease in operating revenues was primarily due to the following:

- PPA capacity revenues increased $23 million ($50 million increase related to affiliates, partially offset by a $27 million decrease related to non-affiliates), primarily due to a 1% increase in total MW capacity contracted with affiliates associated with new natural gas PPAs.
- PPA energy revenues decreased $78 million due to a $141 million decrease primarily related to a 34% decrease in the average price of energy driven by lower natural gas prices passed through in fuel revenues, partially offset by a 13% increase in KWH sales. This decrease in natural gas PPA energy revenues was partially offset by a $63 million increase in energy revenues from PPAs related to the Company's acquisitions of solar and wind facilities. Overall, total KWH sales under PPAs increased 15% in 2015 when compared to 2014.
- Non-PPA revenues decreased $63 million primarily due to lower natural gas prices, partially offset by a 19% increase in non-PPA KWH sales.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. Additionally, the Company purchases a portion of its electricity needs from the wholesale market. Details of the Company's generation and purchased power were as follows:

	Total KWHs	Total KWH % Change	Total KWHs	Total KWH % Change
	2016		2015	
		(in billions of KWHs)		
Generation	37		33	
Purchased power	3		2	
Total generation and purchased power	40	14%	35	17%
Total generation and purchased power excluding solar, wind, and tolling agreements	23	10%	21	5%

The Company's PPAs for natural gas and biomass generation generally provide that the purchasers are responsible for either procuring the fuel (tolling agreements) or reimbursing the Company for substantially all of the cost of fuel relating to the energy

delivered under such PPAs. Consequently, changes in such fuel costs are generally accompanied by a corresponding change in related fuel revenues and do not have a significant impact on net income. The Company is responsible for the cost of fuel for generating units that are not covered under PPAs. Power from these generating units is sold into the wholesale market or into the power pool for capacity owned directly by the Company.

Purchased power expenses will vary depending on demand, availability, and the cost of generating resources throughout the Southern Company system and other contract resources. Load requirements are submitted to the power pool on an hourly basis and are fulfilled with the lowest cost alternative, whether that is generation owned by the Company, an affiliate company, or external parties. Such purchased power costs are generally recovered through PPA revenues.

Details of the Company's fuel and purchased power expenses were as follows:

	2016	2015	2014
		(in millions)	
Fuel	**$ 456**	$ 441	$ 596
Purchased power	**102**	93	171
Total fuel and purchased power expenses	**$ 558**	$ 534	$ 767

In 2016 , total fuel and purchased power expenses increased $24 million, or 5%, compared to 2015 . The increase was primarily due to the following:

- Fuel expense increased $15 million, or 3%, primarily due to a $22 million increase associated with the volume of KWHs generated, partially offset by a $7 million decrease associated with the average cost of natural gas per KWH generated.
- Purchased power expense increased $9 million, or 10%, primarily due to a $53 million increase associated with the volume of KWHs purchased, partially offset by a $28 million decrease associated with the average cost of purchased power and a $16 million decrease associated with a PPA expiration.

In 2015 , total fuel and purchased power expenses decreased $233 million, or 30%, compared to 2014 . The decrease was primarily due to the following:

- Fuel expense decreased $155 million, or 26%, primarily due to a $228 million decrease associated with the average cost of natural gas per KWH generated, partially offset by a $73 million increase associated with the volume of KWHs generated.
- Purchased power expense decreased $78 million, or 46%, primarily due to a $60 million decrease associated with the volume of KWHs purchased as well as an $18 million decrease associated with the average cost of purchased power.

Other Operations and Maintenance Expenses

In 2016 , other operations and maintenance expenses increased $94 million, or 36%, compared to 2015 . The increase was primarily due to increases of $35 million associated with new plants placed in service in 2015 and 2016, $25 million associated with scheduled outage and maintenance expenses, $19 million in business development and support expenses, $13 million in employee compensation, and $2 million in acquisition costs, all of which were primarily associated with the Company's overall growth.

In 2015 , other operations and maintenance expenses increased $23 million, or 10%, compared to 2014 . The increase was primarily due to increases of $11 million associated with new plants placed in service in 2014 and 2015, $10 million in business development and support services expenses, $5 million in transmission costs, and $3 million in employee compensation. These increases were partially offset by a $6 million decrease in generation maintenance expense.

Depreciation and Amortization

In 2016 , depreciation and amortization increased $104 million, or 42%, compared to 2015 . In 2015 , depreciation and amortization increased $28 million, or 13%, compared to 2014 . These increases were primarily due to additional depreciation related to new solar and wind facilities placed in service. See Note 1 to the financial statements under "Depreciation" for additional information.

Interest Expense, Net of Amounts Capitalized

In 2016 , interest expense, net of amounts capitalized increased $40 million, or 52%, compared to 2015 . The increase was primarily due to an increase of $66 million in interest expense related to additional debt issued during 2016 primarily to fund the Company's growth strategy and continuous construction program, partially offset by a $26 million increase in capitalized interest associated with the construction of solar facilities.

In 2015 , interest expense, net of amounts capitalized decreased $12 million, or 13%, compared to 2014 . The decrease was primarily due to a $14 million increase in capitalized interest associated with the construction of solar facilities, partially offset by an increase of $2 million in interest expense related to additional debt issued to fund the Company's growth strategy and continuous construction program.

Other Income (Expense), Net

In 2016 , other income (expense), net increased $5 million compared to 2015 . The increase was due to a $5 million increase in interest received. In addition, the change includes an $82 million currency gain arising from translation of €1.1 billion euro-denominated fixed-rate notes into U.S dollars, fully offset by an $82 million loss on the foreign currency hedge that was reclassified from AOCI into earnings. See Note 9 to the financial statements under "Foreign Currency Derivatives" for additional information regarding hedging.

In 2015 , other income (expense), net decreased $5 million compared to 2014 . The decrease was due to the recognition of a $5 million bargain purchase gain recognized in 2014 arising from the acquisition of a solar facility.

Income Taxes (Benefit)

In 2016 , income taxes (benefit) was $(195) million compared to an expense of $21 million for 2015 . The $216 million change was primarily due to an increase of $180 million in federal income tax benefits related to ITCs for solar plants placed in service and PTCs from wind generation in 2016 and a $35 million decrease in tax expense related to lower pre-tax earnings in 2016.

In 2015 , income taxes (benefit) increased $24 million compared to 2014 . The increase was primarily due to a $26 million increase associated with higher pre-tax earnings and a $9 million increase resulting from state apportionment rate changes, partially offset by an $11 million increase in federal income tax benefits primarily related to ITCs for solar plants placed in service in 2015 .

See Note 1 to the financial statements under "Income and Other Taxes" for information on how the Company recognizes the tax benefits related to federal ITCs and PTCs and Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Effects of Inflation

The Company is party to long-term contracts reflecting market-based rates, including inflation expectations. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The results of operations for the past three years are not necessarily indicative of the Company's future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's competitive wholesale business. These factors include: the Company's ability to achieve sales growth while containing costs; regulatory matters; creditworthiness of customers; total generating capacity available in the Company's market areas; the successful remarketing of capacity as current contracts expire; the Company's ability to execute its growth strategy, including successful additional investments in renewable and other energy projects, and to develop and construct generating facilities. Current proposals related to potential tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals, including any potential changes to the availability or realizability of ITCs and PTCs, is dependent on the final form of any legislation enacted and the related transition rules and cannot be determined at this time, but could have a material impact on the Company's financial statements.

Demand for electricity is primarily driven by economic growth. The pace of economic growth and electricity demand may be affected by changes in regional and global economic conditions, as well as renewable portfolio standards, which may impact future earnings.

Other factors that could influence future earnings include weather, demand, cost of generation from units within the power pool, and operational limitations.

Power Sales Agreements

General

The Company has PPAs with some of Southern Company's traditional electric operating companies, other investor-owned utilities, independent power producers, municipalities, and other load-serving entities. The PPAs are expected to provide the Company with a stable source of revenue during their respective terms.

Many of the Company's PPAs have provisions that require the Company or the counterparty to post collateral or an acceptable substitute guarantee in the event that S&P or Moody's downgrades the credit ratings of the respective company to an unacceptable credit rating or if the counterparty is not rated or fails to maintain a minimum coverage ratio. See FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein for additional information.

The Company is working to maintain and expand its share of the wholesale market. The Company expects that limited additional demand for capacity will begin to develop within some of its market areas in the 2017-2019 timeframe. The Company calculates an investment coverage ratio for its generating assets based on the ratio of investment under contract to total investment using the respective generation facilities' net book value (or expected in-service value for facilities under construction or being acquired) as the investment amount. With the inclusion of the PPAs and investments associated with the solar and natural gas facilities currently under construction and Bethel Wind, which was acquired subsequent to December 31, 2016, as well as other capacity and energy contracts, the Company has an average investment coverage ratio of 91% through 2021 and 90% through 2026, with an average remaining contract duration of approximately 16 years. See "Acquisitions" and "Construction Projects" herein for additional information.

Natural Gas and Biomass

The Company's electricity sales from natural gas and biomass generating units are primarily through long-term PPAs that consist of two types of agreements. The first type, referred to as a unit or block sale, is a customer purchase from a dedicated generating unit where all or a portion of the generation from that unit is reserved for that customer. The Company typically has the ability to serve the unit or block sale customer from an alternate resource. The second type, referred to as requirements service, provides that the Company serve the customer's capacity and energy requirements from a combination of the customer's own generating units and from Company resources not dedicated to serve unit or block sales. The Company has rights to purchase power provided by the requirements customers' resources when economically viable.

As a general matter, substantially all of the PPAs provide that the purchasers are responsible for either procuring the fuel (tolling agreements) or reimbursing the Company for substantially all of the cost of fuel or purchased power relating to the energy delivered under such PPAs. To the extent a particular generating facility does not meet the operational requirements contemplated in the PPAs, the Company may be responsible for excess fuel costs. With respect to fuel transportation risk, most of the Company's PPAs provide that the counterparties are responsible for transporting the fuel to the particular generating facility.

Capacity charges that form part of the PPA payments are designed to recover fixed and variable operation and maintenance costs based on dollars-per-kilowatt year. In general, to reduce the Company's exposure to certain operation and maintenance costs, the Company has LTSAs. See Note 1 to the financial statements under "Long-Term Service Agreements" for additional information.

Solar and Wind

The Company's electricity sales from solar and wind (renewables) generating facilities are also made pursuant to long-term PPAs; however, these solar and wind PPAs do not have a capacity charge and customers either purchase the energy output of a dedicated renewable facility through an energy charge or provide the Company a certain fixed price for the electricity sold to the grid. As a result, the Company's ability to recover fixed and variable operation and maintenance expenses is dependent upon the level of energy generated from these facilities, which can be impacted by weather conditions, equipment performance, and other factors. Generally, under the solar and wind generation PPAs, the purchasing party retains the right to keep or resell the renewable energy credits.

Environmental Matters

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; the Migratory Bird Treaty Act; the Bald and Golden Eagle Protection Act; and related federal and

state regulations. Compliance with possible additional federal or state legislation or regulations related to global climate change, air quality, water quality, or other environmental and health concerns could also significantly affect the Company.

New environmental legislation or regulations, such as requirements related to greenhouse gases or changes to existing statutes or regulations, could affect many areas of the Company's operations. While the Company's PPAs generally contain provisions that permit charging the counterparty with some of the new costs incurred as a result of changes in environmental laws and regulations, the full impact of any such legislative or regulatory changes cannot be determined at this time.

Since the Company's units are newer natural gas and renewable generating facilities, costs associated with environmental compliance for these facilities have been less significant than for similarly situated coal or older natural gas generating facilities. Environmental, natural resource, and land use concerns, including the applicability of air quality limitations, the potential presence of wetlands or threatened and endangered species, the availability of water withdrawal rights, uncertainties regarding aesthetic impacts such as increased light or noise, and concerns about potential adverse health impacts can, however, increase the cost of siting and operating any type of future electric generating facility. The impact of such statutes and regulations on the Company cannot be determined at this time.

Environmental Statutes and Regulations

Air Quality

On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide (NO_x) emissions from power plants in two phases – Phase 1 in 2015 and Phase 2 in 2017. On October 26, 2016, the EPA published a final rule that updates the CSAPR ozone season NO_x program, beginning in 2017, and establishes more stringent ozone-season emissions budgets in Alabama and Texas and removes Florida and North Carolina from the program. The State of Georgia's emission budget was not affected by the revisions, but interstate emissions trading is restricted unless the state decides to voluntarily adopt a significantly reduced budget. Alabama, Georgia, North Carolina, and Texas are also in the CSAPR annual SO_2 and NO_x programs.

In June 2015, the EPA published a final rule requiring certain states (including Alabama, Florida, Georgia, North Carolina, and Texas) to revise or remove the provisions of their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM), and many states have submitted proposed SIP revisions in response to the rule.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. These regulations could result in additional capital expenditures and compliance costs that could affect results of operations, cash flows, and financial condition if such costs are not recovered through PPAs. Further, if higher costs are recovered through regulated rates at other utilities, this could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. The ultimate impact of the CSAPR and SSM rule will depend on various factors, such as implementation, adoption, or other action at the state level, and the outcome of pending and/or future legal challenges, and cannot be determined at this time.

Water Quality

The EPA's final rule establishing standards for reducing effects on fish and other aquatic life caused by new and existing cooling water intake structures at existing power plants and manufacturing facilities became effective in 2014. The effect of this final rule will depend on the results of additional studies that are currently underway and implementation of the rule by regulators based on site-specific factors. National Pollutant Discharge Elimination System (NPDES) permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule.

In November 2015, the EPA published a final effluent guidelines rule which imposes stringent technology-based requirements for certain wastestreams from steam electric power plants. The revised technology-based limits and compliance dates will be incorporated into future renewals of NPDES permits at affected units and may require the installation and operation of multiple technologies sufficient to ensure compliance with applicable new numeric wastewater compliance limits. Compliance deadlines between November 1, 2018 and December 31, 2023 will be established in permits based on information provided for each applicable wastestream.

These water quality regulations could result in additional capital expenditures and compliance costs. Also, results of operations, cash flows, and financial condition could be impacted if such costs are not recovered through PPAs. Based on a preliminary assessment of the impact of the proposed rules, the Company estimates compliance costs to be immaterial. Further, if higher costs are recovered through regulated rates at other utilities, this could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. The ultimate impact of these final rules will depend

on various factors, such as pending and/or future legal challenges, compliance dates, and implementation of the rules, and cannot be determined at this time.

Global Climate Issues

In October 2015, the EPA published two final actions that would limit CO_2 emissions from fossil fuel-fired electric generating units. One of the final actions contains specific emission standards governing CO_2 emissions from new, modified, and reconstructed units. The other final action, known as the Clean Power Plan, establishes guidelines for states to develop plans to meet EPA-mandated CO_2 emission rates or emission reduction goals for existing units. The EPA's final guidelines require state plans to meet interim CO_2 performance rates between 2022 and 2029 and final rates in 2030 and thereafter. At the same time, the EPA published a proposed federal plan and model rule that, when finalized, states can adopt or that would be put in place if a state either does not submit a state plan or its plan is not approved by the EPA. On February 9, 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan, pending disposition of petitions for review with the courts. The stay will remain in effect through the resolution of the litigation, including any review by the U.S. Supreme Court.

These guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through PPAs. Further, if higher costs are recovered through regulated rates at other utilities, this could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. However, the ultimate financial and operational impact of the final rules on the Company cannot be determined at this time and will depend upon numerous factors, including the outcome of pending legal challenges, and any individual state implementation of the EPA's final guidelines in the event the rule is upheld and implemented.

In December 2015, parties to the United Nations Framework Convention on Climate Change – including the United States – adopted the Paris Agreement, which establishes a non-binding universal framework for addressing greenhouse gas emissions based on nationally determined contributions. It also sets in place a process for tracking progress toward the goals every five years. The ultimate impact of this agreement depends on its implementation by participating countries and cannot be determined at this time.

The EPA's greenhouse gas reporting rule requires annual reporting of greenhouse gas emissions expressed in terms of metric tons of CO_2 equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2015 greenhouse gas emissions were approximately 13 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2016 greenhouse gas emissions on the same basis is approximately 13 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation, including new or acquired natural gas-fired plants, the mix of fuel sources, and other factors.

Income Tax Matters

Consolidated Income Taxes

On behalf of the Company, Southern Company files a consolidated federal income tax return and various state income tax returns, some of which are combined, unitary, or consolidated. 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.

The impact of certain tax events at Southern Company and/or its other subsidiaries can, and does, affect the Company's ability to utilize certain tax credits. See Note 5 to the financial statements for additional information.

Tax Credits

In December 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. The PATH Act allows for 30% ITC for solar projects that commence construction by December 31, 2019; 26% ITC for solar projects that commence construction in 2020; 22% ITC for solar projects that commence construction in 2021; and a permanent 10% ITC for solar projects that commence construction on or after January 1, 2022. In addition, the PATH Act allows for 100% PTC for wind projects that commenced construction in 2016; 80% PTC for wind projects that commence construction in 2017; 60% PTC for wind projects that commence construction in 2018; and 40% PTC for wind projects that commence construction in 2019. Wind projects commencing construction after 2019 will not be entitled to any PTCs. The Company has received ITCs related to its investment in new solar facilities acquired or constructed and receives PTCs related to the first 10 years of energy production from its wind facilities, which have had, and will continue to have, a material impact on the Company's cash flows and net

income. At December 31, 2016, the Company had approximately $1.7 billion of unutilized ITCs and PTCs, which are currently expected to be fully utilized by 2022, but could be further delayed as a result of the Company's continued growth strategy, as well as the impact of potential tax reform legislation. See Note 1 to the financial statements under "Income and Other Taxes" and Note 5 to the financial statements under "Current and Deferred Income Taxes – Tax Credit Carryforwards" and "Effective Tax Rate" for additional information regarding utilization and amortization of credits and the tax benefit related to basis differences.

Bonus Depreciation

The PATH Act also extended bonus depreciation for qualified property placed in service over the next five years. The PATH Act allows for 50% bonus depreciation for 2015 through 2017, 40% bonus depreciation for 2018, and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. The extension of bonus depreciation included in the PATH Act is expected to result in approximately $630 million of positive cash flows for the 2016 tax year, which was not all realized in 2016 due to a projected consolidated net operating loss (NOL) for Southern Company. Approximately $150 million of positive cash flows is expected to result from bonus depreciation for the 2017 tax year, but may not all be realized in 2017 due to additional NOL projections for the 2017 tax year. As a result, the NOL increased deferred tax assets for federal ITC and PTC carryforwards. See Note 5 to the financial statements under "Current and Deferred Income Taxes – Tax Credit Carryforwards" and " – Net Operating Loss" for additional information. The ultimate outcome of this matter cannot be determined at this time.

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Acquisitions

During 2016 , in accordance with its overall growth strategy, the Company or one of its wholly-owned subsidiaries, SRP and SRE, acquired or contracted to acquire the projects discussed below. Also, on March 29, 2016, the Company acquired an additional 15% interest in Desert Stateline, 51% of which was initially acquired in August 2015. As a result, the Company and the class B member are now entitled to 66% and 34% , respectively, of all cash distributions from Desert Stateline. In addition, the Company will continue to be entitled to substantially all of the federal tax benefits with respect to the transaction. See Note 2 to the financial statements for additional information.

Project Facility	Resource	Approximate Nameplate Capacity (*MW*)	Location	Percentage Ownership		Actual/Expected COD	PPA Counterparties	PPA Contract Period
Acquisitions During the Year Ended December 31, 2016								
Boulder 1	Solar	100	Clark County, NV	51%	(a)	December 2016	Nevada Power Company	20 years
Calipatria	Solar	20	Imperial County, CA	90%	(b)	February 2016	San Diego Gas & Electric Company	20 years
East Pecos	Solar	120	Pecos County, TX	100%		March 2017	Austin Energy	15 years
Grant Plains	Wind	147	Grant County, OK	100%		December 2016	Oklahoma Municipal Power Authority and Steelcase Inc.	20 years and 12 years (c)
Grant Wind	Wind	151	Grant County, OK	100%		April 2016	Western Farmers, East Texas, and Northeast Texas Electric Cooperatives	20 years
Henrietta	Solar	102	Kings County, CA	51%	(a)	July 2016	Pacific Gas & Electric Company	20 years
Lamesa	Solar	102	Dawson County, TX	100%		Second quarter 2017	City of Garland, Texas	15 years
Mankato (d)	Natural Gas	375	Mankato, MN	100%		N/A (e)	Northern States Power Company	10 years
Passadumkeag	Wind	42	Penobscot County, ME	100%		July 2016	Western Massachusetts Electric Company	15 years
Rutherford	Solar	74	Rutherford County, NC	90%	(b)	December 2016	Duke Energy Carolinas, LLC	15 years
Salt Fork	Wind	174	Donley and Gray Counties, TX	100%		December 2016	City of Garland, Texas and Salesforce.com, Inc.	14 years and 12 years
Tyler Bluff	Wind	125	Cooke County, TX	100%		December 2016	The Proctor & Gamble Company	12 years
Wake Wind	Wind	257	Floyd and Crosby Counties, TX	90.1%	(f)	October 2016	Equinix Enterprises, Inc. and Owens Corning	12 years
Acquisitions Subsequent to December 31, 2016								
Bethel	Wind	276	Castro County, TX	100%		January 2017	Google Energy, Inc.	12 years

(a) The Company owns 100% of the class A membership interests and a wholly-owned subsidiary of the seller owns 100% of the class B membership interests. The Company and the class B member are entitled to 51% and 49% , respectively, of all cash distributions from the project. In addition, the Company is entitled to substantially all of the federal tax benefits with respect to the transaction.
(b) The Company owns 90%, with the minority owner, TRE, owning 10%.
(c) In addition to the 20 -year and 12 -year PPAs, the facility has a 10 -year contract with Allianz Risk Transfer (Bermuda) Ltd.
(d) Under the terms of the remaining 10-year PPA and the 20-year expansion PPA, approximately $408 million of assets, primarily related to property, plant, and equipment, are subject to lien at December 31, 2016.
(e) The acquisition included a fully operational 375 -MW natural gas-fired combined-cycle facility.
(f) The Company owns 90.1%, with the minority owner, Invenergy, owning 9.9%.

Acquisitions During the Year Ended December 31, 2016

The Company's aggregate purchase price of acquisitions during the year ended December 31, 2016 was approximately $2.3 billion , of which $461 million is included in acquisitions payable on the consolidated balance sheets at December 31, 2016 .

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The aggregate amount of revenue recognized by the Company related to the acquisitions during 2016, included in the consolidated statement of income for 2016 , is $37 million . The amount of net income, excluding impacts of ITCs and PTCs, attributable to the Company related to the acquisitions during 2016 included in the consolidated statement of income is immaterial.

The solar and wind acquisitions did not have operating revenues or net income prior to the completion of construction and the generating facility being placed in service; therefore, supplemental pro forma information as if these acquisitions occurred as of the beginning of 2016 , and for the comparable 2015 year, is not meaningful and has been omitted. However, the Mankato acquisition is an operating facility and unaudited supplemental pro forma information, as though the acquisition occurred as of the beginning of 2016 and for the comparable 2015 year, is as follows:

	2016	2015
	(in millions)	
Revenues	$ 40,000,000	$ 39,000,000
Net income	$ 14,000,000	$ 11,000,000

These unaudited pro forma results are for comparative purposes only and may not be indicative of the results that would have occurred had this acquisition been completed on January 1, 2015 or the results that may be attained in the future.

Construction Projects

Construction Projects Completed

During 2016 , in accordance with its overall growth strategy, the Company completed construction of, and placed in service, the projects set forth in the following table. Total costs of construction incurred for these projects were $ 3.2 billion .

Solar Facility	Approximate Nameplate Capacity (*MW*)	Location	Actual COD	PPA Counterparties	PPA Contract Period
Projects Completed During the Year Ended December 31, 2016					
Butler	103	Taylor County, GA	December 2016	Georgia Power [(a)]	30 years
Butler Solar Farm	22	Taylor County, GA	February 2016	Georgia Power [(a)]	20 years
Desert Stateline	299 [(b)]	San Bernardino County, CA	From December 2015 to July 2016	SCE	20 years
Garland	185	Kern County, CA	October 2016	SCE	15 years
Garland A	20	Kern County, CA	August 2016	SCE	20 years
Pawpaw	30	Taylor County, GA	March 2016	Georgia Power [(a)]	30 years
Roserock [(c)]	160	Pecos County, TX	November 2016	Austin Energy	20 years
Sandhills	146	Taylor County, GA	October 2016	Cobb, Flint, Irwin, Middle Georgia and Sawnee Electric Membership Corporations	25 years
Tranquillity	205	Fresno County, CA	July 2016	Shell Energy North America (US), LP/SCE	18 years

(a) Affiliate PPA approved by the FERC.
(b) The facility has a total of 299 MWs, of which 110 MWs were placed in service in the fourth quarter 2015 and 189 MWs were placed in service through July 2016.
(c) Prior to placing the Roserock facility in service, certain solar panels were damaged. While the facility is currently generating energy as expected, the Company is pursuing remedies under its insurance policies and other contracts to repair or replace these solar panels.

Construction Projects in Progress

At December 31, 2016 , the Company continued construction of the East Pecos and Lamesa solar facilities that were acquired in 2016. In addition, as part of the Company's acquisition of Mankato in 2016 , the Company commenced construction of an additional 345 -MW natural gas-fired generation expansion, which is fully contracted under a new 20 -year PPA. Total aggregate

construction costs, excluding the acquisition costs, are expected to be $530 million to $590 million for East Pecos, Lamesa, and Mankato. At December 31, 2016 , the construction costs included in CWIP totaled $386 million . The ultimate outcome of these matters cannot be determined at this time.

The following table presents the Company's construction projects in progress as of December 31, 2016:

Project Facility	Resource	Approximate Nameplate Capacity (*MW*)	Location	Actual/Expected COD	PPA Counterparties	PPA Contract Period
East Pecos	Solar	120	Pecos County, TX	March 2017	Austin Energy	15 years
Lamesa	Solar	102	Dawson County, TX	Second quarter 2017	City of Garland, Texas	15 years
Mankato	Natural Gas	345	Mankato, MN	Second quarter 2019	Northern States Power Company	20 years

Development Projects

In December 31, 2016 , as part of the Company's renewable development strategy, SRP entered into a joint development agreement with Renewable Energy Systems Americas, Inc. to develop and construct approximately 3,000 MWs across 10 wind projects expected to be placed in service between 2018 and 2020 . Also in December 2016, the Company signed agreements and made payments to purchase wind turbine equipment from Siemens Wind Power, Inc. and Vestas-American Wind Technology, Inc. to be used for construction of the facilities. Once these wind projects reach commercial operations, they are expected to qualify for 100% PTCs. The ultimate outcome of these matters cannot be determined at this time.

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 and the Company filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric operating companies' and the Company'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 and the Company to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies and the Company filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.

On December 9, 2016, the traditional electric operating companies and the Company 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' and the Company's potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The traditional electric operating companies and the Company expect to make a compliance filing within 30 days accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

The ultimate outcome of these matters cannot be determined at this time.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its consolidated financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Revenue Recognition

The Company's revenue recognition depends on appropriate classification and documentation of transactions in accordance with GAAP. In general, the Company's power sale transactions, which include PPAs, can be classified in one of four categories: leases, non-derivatives or normal sale derivatives, derivatives designated as cash flow hedges, and derivatives not designated as hedges. For more information on derivative transactions, see FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" herein and Notes 1 and 9 to the financial statements. The Company's revenues are dependent upon significant judgments used to determine the appropriate transaction classification, which must be documented upon the inception of each contract.

Lease Transactions

The Company considers the following factors to determine whether the sales contract is a lease:

- Assessing whether specific property is explicitly or implicitly identified in the agreement;
- Determining whether the fulfillment of the arrangement is dependent on the use of the identified property; and
- Assessing whether the arrangement conveys to the purchaser the right to use the identified property.

If the contract meets the above criteria for a lease, the Company performs further analysis as to whether the lease is classified as operating, financing, or sales-type. All of the Company's power sales contracts that are determined to be leases are accounted for as operating leases and the capacity revenue is recognized on a straight-line basis over the term of the contract and is included in the Company's operating revenues. Energy revenues and other contingent revenues are recognized in the period the energy is delivered or the service is rendered.

Non-Derivative and Normal Sale Derivative Transactions

If the power sales contract is not classified as a lease, the Company further considers the following factors to determine proper classification:

- Assessing whether the contract meets the definition of a derivative;
- Assessing whether the contract meets the definition of a capacity contract;
- Assessing the probability at inception and throughout the term of the individual contract that the contract will result in physical delivery; and
- Ensuring that the contract quantities do not exceed available generating capacity (including purchased capacity).

Contracts that do not meet the definition of a derivative or are designated as normal sales (i.e. capacity contracts which provide for the sale of electricity that involve physical delivery in quantities within the Company's available generating capacity) are accounted for as executory contracts. The related capacity revenue, if any, is recognized on an accrual basis in amounts equal to the lesser of the cumulative levelized amount or the cumulative amount billable under the contract over the respective contract periods. Revenues related to energy and ancillary services are recognized in the period the energy is delivered or the service is rendered. Contracts recorded on the accrual basis represented the majority of the Company's operating revenues.

Cash Flow Hedge Transactions

The Company further considers the following in designating other derivative contracts for the sale of electricity as cash flow hedges of anticipated sale transactions:

- Identifying the hedging instrument, the forecasted hedged transaction, and the nature of the risk being hedged; and

- Assessing hedge effectiveness at inception and throughout the contract term.

These contracts are accounted for on a fair value basis and are recorded in AOCI over the life of the contract. Realized gains and losses are then recognized in operating revenues as incurred.

Mark-to-Market Transactions

Contracts for sales of electricity, which meet the definition of a derivative and that either do not qualify or are not designated as normal sales or as cash flow hedges, are accounted for on a fair value basis and are recorded in operating revenues.

Impairment of Long-Lived Assets and Intangibles

The Company's investments in long-lived assets are primarily generation assets, whether in service or under construction. The Company's intangible assets arise from certain acquisitions and consist of acquired PPAs, which are amortized to revenue over the term of the respective PPAs. The Company evaluates the carrying value of these assets whenever indicators of potential impairment exist. Examples of impairment indicators could include significant changes in construction schedules, current period losses combined with a history of losses or a projection of continuing losses, a significant decrease in market prices, and the inability to remarket generating capacity for an extended period. If an indicator exists, the asset is tested for recoverability by comparing the asset carrying value to the sum of the undiscounted expected future cash flows directly attributable to the asset. If the estimate of undiscounted future cash flows is less than the carrying value of the asset, the fair value of the asset is determined and a loss is recorded. A high degree of judgment is required in developing estimates related to these evaluations, which are based on projections of various factors, including the following:

- Future demand for electricity based on projections of economic growth and estimates of available generating capacity;
- Future power and natural gas prices, which have been quite volatile in recent years; and
- Future operating costs.

Acquisition Accounting

The Company acquires generation assets as part of its overall growth strategy. For acquisitions that meet the definition of a business, the Company includes the operations in its consolidated financial statements from the respective date of acquisition. The purchase price, including contingent consideration, if any, of each acquisition is allocated based on the fair value of the identifiable assets and liabilities, including the identification of any intangible assets. Assets acquired that do not meet the definition of a business are accounted for as asset acquisitions. The purchase price of each asset acquisition is allocated based on the relative fair value of assets acquired. Any due diligence or transition costs incurred by the Company for successful or potential acquisitions are expensed as incurred.

Investment Tax Credits

Under current tax legislation, certain construction costs related to renewable generating assets are eligible for federal ITCs. A high degree of judgment is required in determining which construction expenditures qualify for federal ITCs and estimates of eligible costs which, as they relate to acquisitions, may not be finalized until the allocation of purchase price to assets has been finalized. See Note 1 to the financial statements under "Income and Other Taxes" for additional information.

Recently Issued Accounting Standards

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers,* replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

While the Company expects most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of such arrangements. The Company's ongoing evaluation of revenue streams and related contracts includes the evaluation of identified revenue streams tied to longer term contractual arrangements, such as certain capacity payments under PPAs that are expected to be excluded from the scope of ASC 606 and included in the scope of the current leasing guidance (ASC Topic 840).

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. The Company must select a transition method to be applied either retrospectively to each prior reporting period presented or retrospectively with a cumulative effect adjustment to retained earnings at the date of initial adoption. However, given the Company's core activities of selling generation capacity and energy to high credit rated customers, the Company currently does not expect the new standard to

have a significant impact to net income. The Company has not elected a transition method as the ultimate impact of the new standard has not yet been determined.

On February 25, 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged . ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company is currently evaluating the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

On October 24, 2016, the FASB issued ASU No. 2016-16, *Income Taxes (Topic 740), Intra-Entity Transfers of Assets Other Than Inventory* (ASU 2016-16). Current GAAP prohibits the recognition of current and deferred income taxes for an affiliate asset transfer until the asset has been sold to an outside party. ASU 2016-16 requires an entity to recognize the income tax consequences of an affiliate transfer of an asset other than inventory when the transfer occurs. ASU 2016-16 is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. The amendments will be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The Company is currently assessing the impact of the standard on its financial statements and has not yet determined its ultimate impact.

On November 17, 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* (ASU 2016-18). ASU 2016-18 eliminates the need to reflect transfers between cash and restricted cash in operating, investing, and financing activities in the statement of cash flows. Upon adoption, the net change in cash and cash equivalents during the period will include amounts generally described as restricted cash or restricted cash equivalents. ASU 2016-18 is effective for fiscal years beginning after December 15, 2017, with early adoption permitted, and will be applied retrospectively to each period presented. The Company does not intend to adopt the guidance early. The adoption of ASU 2016-18 will not have a material impact on the financial statements of the Company.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2016 . The Company's cash requirements primarily consist of funding ongoing business operations, common stock dividends and distributions to noncontrolling interests, capital expenditures, and debt maturities. Capital expenditures and other investing activities may include investments in acquisitions or new construction associated with the Company's overall growth strategy and to maintain the existing generation fleet's performance. Operating cash flows, which may include the utilization of unutilized tax credits, will only provide a portion of the Company's cash needs. For the three-year period from 2017 through 2019, the Company's projected 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 debt issuances and equity contributions from Southern Company. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit agreements as needed to meet its future capital and liquidity needs. See "Sources of Capital" herein for additional information on lines of credit.

Net cash provided from operating activities totaled $339 million in 2016 , a decrease of $664 million compared to 2015 . The decrease in net cash provided from operating activities was primarily due to an increase in unutilized ITCs and PTCs. As of December 31, 2016 , the Company had $1.7 billion of unutilized ITCs and PTCs which are not expected to be fully utilized until 2022. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Tax Credits" herein for additional information. Net cash provided from operating activities totaled $1.0 billion in 2015 and $ 603 million in 2014 . This increase was primarily due to an increase in income tax benefits received and increased revenues from new PPAs.

Net cash used for investing activities totaled $4.8 billion , $2.5 billion , and $814 million in 2016 , 2015 , and 2014 , respectively, and was primarily due to acquisitions and the construction of renewable and natural gas facilities. See FUTURE EARNINGS POTENTIAL – "Acquisitions" and "Construction Projects" herein for additional information.

Net cash provided from financing activities totaled $4.7 billion , $2.3 billion , and $217 million in 2016 , 2015 , and 2014 , respectively. Net cash provided from financing activities in 2016 was primarily due to the issuance of additional senior notes and capital contributions from Southern Company. Net cash provided from financing activities in 2015 was due to the issuance of additional senior notes and a 13-month bank loan. Net cash provided from financing activities in 2014 was primarily due to the issuance of commercial paper.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Significant balance sheet changes include a $5.5 billion increase in plant in service and a $739 million decrease in CWIP primarily due to new solar and wind facilities being acquired or placed in service. In addition, ITC benefits that are deferred and amortized over the asset lives increased $950 million as a result of new solar facilities being placed in service. Other significant changes include a $2.3 billion increase in long-term debt due to issuances of senior notes and a $1.8 billion increase in paid in capital due to equity contributions from Southern Company, both primarily to fund acquisitions and construction projects.

Sources of Capital

The Company plans to obtain the funds required for acquisitions, construction, development, and other purposes from operating cash flows, short-term debt, securities issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors. With respect to the public offering of securities, the Company (excluding its subsidiaries) issues and offers debt registered on registration statements filed with the SEC under the Securities Act of 1933, as amended.

The Company's current liabilities sometimes exceed current assets due to the use of short-term debt as a funding source, and construction payables, as well as fluctuations in cash needs, due to both seasonality and the stage of acquisitions and construction projects. In 2017, the Company expects to utilize the debt capital markets, bank term loans, and commercial paper markets as the source of funds for the majority of its debt maturities, which includes the maturity of $ 500 million aggregate principal amount of Series 2015D 1.85% Senior Notes due December 1, 2017.

The Company obtains financing separately without credit support from any affiliate. To meet liquidity and capital resource requirements, the Company had at December 31, 2016 cash and cash equivalents of approximately $1.1 billion .

The Company believes the need for working capital can be adequately met by utilizing the commercial paper program and credit facilities, as discussed below, as well as bank term loans and operating cash flows.

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes, including maturing debt. The Company's subsidiaries are not issuers under the commercial paper program.

Details of commercial paper were as follows:

	Commercial Paper at the End of the Period		Commercial Paper During the Period (*)		
	Amount Outstanding	Weighted Average Interest Rate	Average Amount Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2016	**$ —**	**N/A**	**$ 56**	**0.8%**	**$ 310**
December 31, 2015	$ —	N/A	$ 166	0.5%	$ 385
December 31, 2014	$ 195	0.4%	$ 54	0.4%	$ 445

(*) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2016 , 2015 , and 2014 .

Company Credit Facilities

At December 31, 2016 , the Company had a committed credit facility (Facility) of $ 600 million expiring in 2020, of which $ 78 million has been used for letters of credit and $ 522 million remains unused. The Company's subsidiaries are not borrowers under the Facility. Proceeds from the Facility may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program. Subject to applicable market conditions, the Company expects to renew or replace the Facility, as needed, prior to expiration. In connection therewith, the Company may extend the maturity date and/or increase or decrease the lending commitment thereunder. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Facility, as well as the Company's term loan agreement, contains a covenant that limits the ratio of debt to capitalization (as defined in the Facility) to a maximum of 65% and contains a cross default provision that is restricted only to indebtedness of the Company. For purposes of this definition, debt excludes any project debt incurred by certain subsidiaries of the Company to the extent such debt is non-recourse to the Company, and capitalization excludes the capital stock or other equity attributable to such subsidiary. The Company is currently in compliance with all covenants in the Facility.

In December 2016, the Company entered into an agreement for a $120 million continuing letter of credit facility for standby letters of credit expiring in 2019. At December 31, 2016, the total amount available under the facility was $82 million. The Company's subsidiaries are not parties to the facility.

Subsidiary Project Credit Facilities

In connection with the construction of solar facilities by RE Tranquillity LLC, RE Roserock LLC, and RE Garland Holdings LLC, indirect subsidiaries of the Company, each subsidiary entered into separate credit agreements (Project Credit Facilities), which were non-recourse to the Company (other than the subsidiary party to the agreement). Each Project Credit Facility provided (a) a senior secured construction loan credit facility, (b) a senior secured bridge loan facility, and (c) a senior secured letter of credit facility that was secured by the membership interests of the respective project company, with proceeds directed to finance project costs related to the respective solar facilities. Each Project Credit Facility was secured by the assets of the applicable project subsidiary and membership interests of the applicable project subsidiary. The Tranquillity and Garland Project Credit Facilities were fully repaid on October 14, 2016 and December 29, 2016, respectively. The table below summarizes the Roserock Project Credit Facility as of December 31, 2016, which was extended to and fully repaid on January 31, 2017.

Project	Construction Loan Facility	Bridge Loan Facility	Total Loan Facility	Loan Facility Undrawn	Letter of Credit Facility	Letter of Credit Facility Undrawn
				(in millions)		
Roserock	$ 63	$ 180	$ 243	$ 34	$ 23	$ 16

The Project Credit Facilities had total amounts outstanding as of December 31, 2016 of $209 million at a weighted average interest rate of 2.1% . For the year ended December 31, 2016 , the Project Credit Facilities had a maximum amount outstanding of $828 million and an average amount outstanding of $566 million at a weighted average interest rate of 2.1% .

Furthermore, in connection with the acquisition of the Henrietta solar facility on July 1, 2016, a subsidiary of the Company assumed a $217 million construction loan, which was fully repaid in September 2016. During this period, the credit agreement had a maximum amount outstanding of $217 million and an average amount outstanding of $137 million at a weighted average interest rate of 2.2%.

Financing Activities

Senior Notes

In June 2016, the Company issued € 600 million aggregate principal amount of Series 2016A 1.00% Senior Notes due June 20, 2022 and € 500 million aggregate principal amount of Series 2016B 1.85% Senior Notes due June 20, 2026. The net proceeds are being allocated to renewable energy generation projects. The Company's obligations under its euro-denominated fixed-rate notes were effectively converted to fixed-rate U.S. dollars at issuance through cross-currency swaps, mitigating foreign currency exchange risk associated with the interest and principal payments. See Note 9 to the financial statements under "Foreign Currency Derivatives" for additional information.

In September 2016, the Company issued $290 million aggregate principal amount of Series 2016C 2.75% Senior Notes due September 20, 2023. The proceeds were used for general corporate purposes, including the Company's growth strategy and continuous construction program, as well as repayment of amounts outstanding under the Project Credit Facilities.

In November 2016, the Company issued $600 million aggregate principal amount of Series 2016D 1.95% Senior Notes due December 15, 2019, $300 million aggregate principal amount of Series 2016E 2.50% Senior Notes due December 15, 2021, and $400 million aggregate principal amount of Series 2016F 4.95% Senior Notes due December 15, 2046. The net proceeds of the Series 2016D and the Series 2016E Senior Notes are being allocated to renewable energy generation projects. The proceeds of the Series 2016F Senior Notes were used to redeem, in December 2016, all of the $200 million aggregate principal amount of the Company's Series E 6.375% Senior Notes due November 15, 2036 and to repay outstanding short-term indebtedness.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Other Debt

In September 2016, the Company repaid $80 million of an outstanding $400 million floating rate bank loan and extended the maturity date of the remaining $320 million from September 2016 to September 2018. In addition, the Company entered into a

$60 million aggregate principal amount floating rate bank loan bearing interest based on one-month LIBOR due September 2017. The proceeds were used to repay existing indebtedness and for other general corporate purposes.

During 2016 , the Company repaid $6 million and issued $5 million of long-term notes payable to TRE.

In addition, during 2016 , the Company issued a total of $89 million in letters of credit under the Company's credit facilities.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and/or Baa2 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, energy price risk management, transmission, and foreign currency risk management.

The maximum potential collateral requirements under these contracts at December 31, 2016 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements	
	(in millions)	
At BBB and/or Baa2	$	38
At BBB- and/or Baa3	$	411
At BB+ and/or Ba1 (*)	$	1,167

(*) Any additional credit rating downgrades at or below BB- and/or Ba3 could increase collateral requirements up to an additional $91 million .

Included in these amounts are certain agreements that could require collateral in the event that Alabama Power or Georgia Power has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of the Company to access capital markets and would be likely to impact the cost at which it does so.

In addition, the Company has a PPA that could require collateral, but not accelerated payment, in the event of a downgrade of the Company's credit. The PPA requires credit assurances without stating a specific credit rating. The amount of collateral required would depend upon actual losses resulting from a credit downgrade.

On January 10, 2017, S&P revised its credit rating outlook for the Company from negative to stable.

Market Price Risk

The Company is exposed to market risks, primarily commodity price risk, interest rate risk, and occasionally foreign currency exchange 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 consolidated balance sheets as either assets or liabilities and are presented on a gross basis. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

At December 31, 2016 , the Company had $380 million of long-term variable rate notes outstanding. The effect on annualized interest expense related to variable interest rate exposure if the Company sustained a 100 basis point change in interest rates is immaterial. Since a significant portion of outstanding indebtedness bears interest at fixed rates, the Company is not aware of any facts or circumstances that would significantly affect exposure on existing indebtedness in the near term. However, the impact on future financing costs cannot be determined at this time.

The Company had foreign currency denominated debt of €1.1 billion at December 31, 2016. The Company has mitigated its exposure to foreign currency exchange rate risk through the use of foreign currency swaps converting all interest and principal payments to fixed-rate U.S. dollars.

Because energy from the Company's facilities is primarily sold under long-term PPAs with tolling agreements and provisions shifting substantially all of the responsibility for fuel cost to the counterparties, the Company's exposure to market volatility in

commodity fuel prices and prices of electricity is generally limited. However, the Company has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of uncontracted generating capacity.

For the years ended December 31, 2016 and 2015, the changes in fair value of energy-related derivative contracts associated with both power and natural gas positions were as follows:

	2016	2015
	(in millions)	
Contracts outstanding at the beginning of period, assets (liabilities), net	**$ 1**	$ 2
Contracts realized or settled	**(3)**	(1)
Current period changes [(*)]	**18**	—
Contracts outstanding at the end of period, assets (liabilities), net	**$ 16**	$ 1

(*) Current period changes also include changes in the fair value of new contracts entered into during the period, if any.

For the years ending December 31, 2016 and 2015, the changes in contracts outstanding were attributable to both the volume and the prices of power and natural gas as follows:

	2016	2015
Power – net sold		
MWH (in millions)	**6.1**	1.8
Weighted average contract cost per MWH above (below) market prices (in dollars)	**$ 1.45**	$ (0.08)
Gas – net purchased		
Commodity - mmBtu	**27.1**	9.6
Commodity - weighted average contract cost per mmBtu above (below) market prices (in dollars)	**$ (0.27)**	$ (0.14)

Gains and losses on energy-related derivatives designated as cash flow hedges which are used by the Company to hedge anticipated purchases and sales are initially deferred in OCI before being recognized in income in the same period as the hedged transactions are reflected in earnings. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the consolidated statements of income as incurred.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2 of the fair value hierarchy. See Note 8 to the financial statements for further discussion of fair value measurements. The energy-related derivative contracts outstanding at December 31, 2016 all mature in 2017.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by S&P and Moody's or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance. See Note 1 to the financial statements under "Financial Instruments" and Note 9 to the financial statements for additional information.

Capital Requirements and Contractual Obligations

The capital program of the Company is currently estimated to total $1.6 billion each year from 2017 through 2021. The capital program is subject to periodic review and revision. These amounts include estimates for potential plant acquisitions and new construction. In addition, the capital program includes capital improvements and work to be performed under LTSAs. Planned expenditures for plant acquisitions may vary materially due to market opportunities and the Company's ability to execute its growth strategy. Actual construction costs may vary from these estimates because of numerous factors such as: changes in business conditions; changes in the expected environmental compliance program; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in FERC rules and regulations; changes in load projections; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. See Note 2 to the financial statements for additional information.

In addition, TRE can require the Company to purchase its redeemable noncontrolling interests in STR, which owns various solar facilities contracted under long-term PPAs, at fair market value pursuant to the partnership agreement and SunPower can require the Company to purchase its redeemable noncontrolling interest in Boulder 1 at fair market value until April 30, 2017. At December 31, 2016 , the aggregate redeemable noncontrolling interests totaled $164 million on the Company's balance sheet.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, leases, derivative obligations, unrecognized tax benefits, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 5, 6, 7, and 9 to the financial statements for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Power Company and Subsidiary Companies 2016 Annual Report

Contractual Obligations

Contractual obligations at December 31, 2016 were as follows:

	2017	2018-2019	2020-2021	After 2021	Total
			(in millions)		
Long-term debt [(a)] —					
Principal	$ 561	$ 1,270	$ 600	$ 3,321	$ 5,752
Interest	184	335	294	1,667	2,480
Financial derivative obligations [(b)]	5	—	—	—	5
Operating leases [(c)]	18	39	40	762	859
Unrecognized tax benefits [(d)]	17	—	—	—	17
Purchase commitments —					
Capital [(e)]	1,525	3,080	3,064	—	7,669
Fuel [(f)]	515	684	393	99	1,691
Purchased power [(g)]	39	81	83	—	203
Other [(h)]	223	200	514	2,007	2,944
Total	$ 3,087	$ 5,689	$ 4,988	$ 7,856	$ 21,620

(a) All amounts are reflected based on final maturity dates and include the effects of interest rate derivatives employed to manage interest rate risk and effects of foreign currency swaps employed to manage foreign currency exchange rate risk. Included in debt principal is $82 million related to the foreign currency hedge of €1.1 billion. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.
(b) For additional information, see Notes 1 and 9 to the financial statements.
(c) Operating lease commitments include certain land leases for solar and wind facilities that are subject to annual price escalation based on indices. See Note 7 to the financial statements under "Commitments" for additional information.
(d) See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.
(e) The Company provides estimated capital expenditures for a five-year period, including capital expenditures associated with environmental regulations. Amounts represent current estimates of total expenditures, excluding capital expenditures covered under LTSAs which are reflected in "Other." See Note (h) below. At December 31, 2016, significant purchase commitments were outstanding in connection with the construction program.
(f) Primarily includes commitments to purchase, transport, and store natural gas fuel. Amounts reflected are based on contracted cost and may contain provisions for price escalation. Amounts reflected for natural gas purchase commitments are based on various indices at the time of delivery and have been estimated based on the New York Mercantile Exchange future prices at December 31, 2016 .
(g) Purchased power commitments will be resold under a third party agreement at cost.
(h) Includes commitments related to LTSAs, operation and maintenance agreements, and transmission. LTSAs include price escalation based on inflation indices. Transmission commitments are based on the Southern Company system's current tariff rate for point-to-point transmission.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2016 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for the Company's business, economic conditions, fuel and environmental cost recovery , current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, financing activities, estimated sales and purchases under power sale and purchase agreements, timing of expected future capacity need in existing markets, completion dates of construction projects, filings with federal regulatory authorities, impact of the PATH Act, federal income tax benefits, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws regulating emissions, discharges, and disposal to air, water, and land , and also changes in tax and other laws and regulations to which the Company is subject, including potential tax reform legislation, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries ;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of generating facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any environmental performance standards , including the requirements of tax credits and other incentives ;
- advances in technology;
- state and federal rate regulations ;
- the ability to successfully operate generating facilities and the successful performance of necessary corporate functions;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ongoing renewable energy partnerships and development agreements;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general ;
- the ability of the Company to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;

- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2016 , 2015 , and 2014
Southern Power Company and Subsidiary Companies 2016 Annual Report

	2016	2015	2014
		(in millions)	
Operating Revenues:			
Wholesale revenues, non-affiliates	**$ 1,146**	$ 964	$ 1,116
Wholesale revenues, affiliates	**419**	417	383
Other revenues	**12**	9	2
Total operating revenues	**1,577**	1,390	1,501
Operating Expenses:			
Fuel	**456**	441	596
Purchased power, non-affiliates	**81**	72	105
Purchased power, affiliates	**21**	21	66
Other operations and maintenance	**354**	260	237
Depreciation and amortization	**352**	248	220
Taxes other than income taxes	**23**	22	22
Total operating expenses	**1,287**	1,064	1,246
Operating Income	**290**	326	255
Other Income and (Expense):			
Interest expense, net of amounts capitalized	**(117)**	(77)	(89)
Other income (expense), net	**6**	1	6
Total other income and (expense)	**(111)**	(76)	(83)
Earnings Before Income Taxes	**179**	250	172
Income taxes (benefit)	**(195)**	21	(3)
Net Income	**374**	229	175
Less: Net income attributable to noncontrolling interests	**36**	14	3
Net Income Attributable to the Company	**$ 338**	$ 215	$ 172

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2016 , 2015 , and 2014
Southern Power Company and Subsidiary Companies 2016 Annual Report

	2016	2015	2014
		(in millions)	
Net Income	**$ 374**	$ 229	$ 175
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(17), $-, and $-, respectively	**(27)**	—	—
Reclassification adjustment for amounts included in net income, net of tax of $36, $-, and $-, respectively	**58**	1	—
Total other comprehensive income	**31**	1	—
Less: Comprehensive income attributable to noncontrolling interests	**36**	14	3
Comprehensive Income Attributable to the Company	**$ 369**	$ 216	$ 172

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2016 , 2015 , and 2014
Southern Power Company and Subsidiary Companies 2016 Annual Report

	2016	2015	2014
		(in millions)	
Operating Activities:			
Net income	**$ 374**	$ 229	$ 175
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**370**	254	225
Deferred income taxes	**(1,063)**	42	(168)
Investment tax credits	**—**	162	74
Amortization of investment tax credits	**(37)**	(19)	(11)
Collateral deposits	**(102)**	—	—
Accrued income taxes, non-current	**(109)**	109	—
Other, net	**—**	(2)	(10)
Changes in certain current assets and liabilities —			
-Receivables	**(54)**	18	(26)
-Prepaid income taxes	**(29)**	(26)	35
-Other current assets	**4**	(4)	(8)
-Accounts payable	**27**	(19)	30
-Accrued taxes	**940**	269	284
-Other current liabilities	**18**	(10)	3
Net cash provided from operating activities	**339**	1,003	603
Investing Activities:			
Business acquisitions	**(2,294)**	(1,719)	(731)
Property additions	**(2,114)**	(1,005)	(21)
Change in construction payables	**(57)**	251	—
Investment in restricted cash	**(733)**	(159)	—
Distribution of restricted cash	**736**	154	—
Payments pursuant to LTSA and for equipment not yet received	**(350)**	(82)	(61)
Other investing activities	**15**	22	(1)
Net cash used for investing activities	**(4,797)**	(2,538)	(814)
Financing Activities:			
Increase (decrease) in notes payable, net	**73**	(58)	195
Proceeds —			
Capital contributions	**1,850**	646	146
Senior notes	**2,831**	1,650	—
Other long-term debt	**65**	402	10
Redemptions —			
Senior notes	**(200)**	(525)	—
Other long-term debt	**(86)**	(4)	(10)
Distributions to noncontrolling interests	**(57)**	(18)	(1)
Capital contributions from noncontrolling interests	**682**	341	8
Purchase of membership interests from noncontrolling interests	**(129)**	—	—
Payment of common stock dividends	**(272)**	(131)	(131)
Other financing activities	**(30)**	(13)	—
Net cash provided from financing activities	**4,727**	2,290	217
Net Change in Cash and Cash Equivalents	**269**	755	6
Cash and Cash Equivalents at Beginning of Year	**830**	75	69
Cash and Cash Equivalents at End of Year	**$ 1,099**	$ 830	$ 75
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $44, $14, and $- capitalized, respectively)	**$ 89**	$ 74	$ 85

Income taxes (net of refunds and investment tax credits)	**116**	(518)	(220)
Noncash transactions —			
Accrued property additions at year-end	**251**	257	1
Acquisitions	**461**	—	229
Capital contributions from noncontrolling interests	**—**	—	221

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED BALANCE SHEETS
At December 31, 2016 and 2015
Southern Power Company and Subsidiary Companies 2016 Annual Report

Assets	**2016**	2015
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 1,099**	$ 830
Receivables —		
Customer accounts receivable	**102**	75
Other accounts receivable	**34**	19
Affiliated	**57**	30
Fossil fuel stock	**15**	16
Materials and supplies	**337**	63
Prepaid income taxes	**74**	45
Other current assets	**39**	30
Total current assets	**1,757**	1,108
Property, Plant, and Equipment:		
In service	**12,728**	7,275
Less accumulated provision for depreciation	**1,484**	1,248
Plant in service, net of depreciation	**11,244**	6,027
Construction work in progress	**398**	1,137
Total property, plant, and equipment	**11,642**	7,164
Other Property and Investments:		
Intangible assets, net of amortization of $22 and $12 at December 31, 2016 and December 31, 2015, respectively	**436**	319
Total other property and investments	**436**	319
Deferred Charges and Other Assets:		
Prepaid long-term service agreements	**101**	166
Accumulated deferred income taxes	**594**	—
Other deferred charges and assets — affiliated	**13**	9
Other deferred charges and assets — non-affiliated	**626**	139
Total deferred charges and other assets	**1,334**	314
Total Assets	**$ 15,169**	$ 8,905

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED BALANCE SHEETS
At December 31, 2016 and 2015
Southern Power Company and Subsidiary Companies 2016 Annual Report

Liabilities and Stockholders' Equity	2016	2015
	(in millions)	
Current Liabilities:		
Securities due within one year	$ **560**	$ 403
Notes payable	**209**	137
Accounts payable —		
Affiliated	**88**	66
Other	**278**	327
Accrued taxes —		
Accrued income taxes	**148**	198
Other accrued taxes	**7**	5
Accrued interest	**36**	23
Acquisitions payable	**461**	—
Contingent consideration	**46**	36
Other current liabilities	**70**	44
Total current liabilities	**1,903**	1,239
Long-Term Debt:		
Senior notes —		
1.85% due 2017	**—**	500
1.50% due 2018	**350**	350
1.95% due 2019	**600**	—
2.375% due 2020	**300**	300
2.50% due 2021	**300**	—
1.00% to 6.375% due 2022-2046	**3,224**	1,575
Other long-term debt —		
Variable rate (1.88% at 1/1/17) due 2018	**320**	—
Variable rate (3.75% at 1/1/17) due 2032-2036	**15**	13
Unamortized debt premium (discount), net	**(12)**	—
Unamortized debt issuance expense	**(29)**	(19)
Long-term debt	**5,068**	2,719
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**152**	601
Accumulated deferred investment tax credits	**1,839**	889
Accrued income taxes, non-current	**—**	109
Asset retirement obligations	**64**	21
Deferred capacity revenues — affiliated	**17**	17
Other deferred credits and liabilities	**287**	3
Total deferred credits and other liabilities	**2,359**	1,640
Total Liabilities	**9,330**	5,598
Redeemable Noncontrolling Interests	**164**	43
Common Stockholder's Equity:		
Common stock, par value $0.01 per share —		
Authorized — 1,000,000 shares		
Outstanding — 1,000 shares	**—**	—
Paid-in capital	**3,671**	1,822
Retained earnings	**724**	657
Accumulated other comprehensive income	**35**	4
Total common stockholder's equity	**4,430**	2,483
Noncontrolling Interests	**1,245**	781
Total Stockholders' Equity	**5,675**	3,264

Total Liabilities and Stockholders' Equity	**$**	**15,169**	$	8,905

Commitments and Contingent Matters (See notes)

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2016 , 2015 , and 2014
Southern Power Company and Subsidiary Companies 2016 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total Common Stockholder's Equity	Noncontrolling Interests [*]	Total
					(in millions)			
Balance at December 31, 2013	—	$ —	$ 1,029	$ 532	$ 3	$ 1,564	$ —	$ 1,564
Net income attributable to Southern Power	—	—	—	172	—	172	—	172
Capital contributions from parent company	—	—	147	—	—	147	—	147
Cash dividends on common stock	—	—	—	(131)	—	(131)	—	(131)
Capital contributions from noncontrolling interests	—	—	—	—	—	—	221	221
Net loss attributable to noncontrolling interests	—	—	—	—	—	—	(2)	(2)
Balance at December 31, 2014	—	—	1,176	573	3	1,752	219	1,971
Net income attributable to Southern Power	—	—	—	215	—	215	—	215
Capital contributions from parent company	—	—	646	—	—	646	—	646
Other comprehensive income	—	—	—	—	1	1	—	1
Cash dividends on common stock	—	—	—	(131)	—	(131)	—	(131)
Capital contributions from noncontrolling interests	—	—	—	—	—	—	567	567
Distributions to noncontrolling interests	—	—	—	—	—	—	(17)	(17)
Net income attributable to noncontrolling interests	—	—	—	—	—	—	12	12
Balance at December 31, 2015	**—**	**—**	**1,822**	**657**	**4**	**2,483**	**781**	**3,264**
Net income attributable to Southern Power	**—**	**—**	**—**	**338**	**—**	**338**	**—**	**338**
Capital contributions from parent company	**—**	**—**	**1,850**	**—**	**—**	**1,850**	**—**	**1,850**
Other comprehensive income	**—**	**—**	**—**	**—**	**31**	**31**	**—**	**31**
Cash dividends on common stock	**—**	**—**	**—**	**(272)**	**—**	**(272)**	**—**	**(272)**
Capital contributions from noncontrolling interests	**—**	**—**	**—**	**—**	**—**	**—**	**618**	**618**
Distributions to noncontrolling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(57)**	**(57)**
Purchase of membership interests from noncontrolling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(129)**	**(129)**
Net income attributable to noncontrolling interests	**—**	**—**	**—**	**—**	**—**	**—**	**32**	**32**
Other	**—**	**—**	**(1)**	**1**	**$ —**	**—**	**—**	**—**
Balance at December 31, 2016	**—**	**$ —**	**$ 3,671**	**$ 724**	**$ 35**	**$ 4,430**	**$ 1,245**	**$ 5,675**

(*) Excludes redeemable noncontrolling interests. See Note 10 to the financial statements under "Noncontrolling Interests" for additional information.

The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO FINANCIAL STATEMENTS
Southern Power Company and Subsidiary Companies 2016 Annual Report

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Southern Power Company and Subsidiary Companies 2016 Annual Report

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Southern Power Company is a wholly-owned subsidiary of Southern Company, which is also the parent company of four traditional electric operating companies, Southern Company Gas (as of July 1, 2016), SCS, Southern LINC, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure, Inc. (PowerSecure) (as of May 9, 2016), and other direct and indirect subsidiaries. The traditional electric operating companies – Alabama Power, Georgia Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power Company and its subsidiaries (the Company) construct, acquire, own, and manage generation assets, including renewable energy projects, and sell electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern LINC provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and for other electric services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.

The preparation of consolidated financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the consolidated financial statements have been reclassified to conform to the current year presentation.

The consolidated financial statements include the accounts of Southern Power Company and its wholly-owned and majority-owned subsidiaries. Intercompany accounts and transactions have been eliminated in consolidation.

Recently Issued Accounting Standards

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers,* replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

While the Company expects most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of such arrangements. The Company's ongoing evaluation of revenue streams and related contracts includes the evaluation of identified revenue streams tied to longer term contractual arrangements, such as certain capacity payments under PPAs that are expected to be excluded from the scope of ASC 606 and included in the scope of the current leasing guidance (ASC Topic 840).

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. The Company must select a transition method to be applied either retrospectively to each prior reporting period presented or retrospectively with a cumulative effect adjustment to retained earnings at the date of initial adoption. However, given the Company's core activities of selling generation capacity and energy to high credit rated customers, the Company currently does not expect the new standard to have a significant impact to net income. The Company has not elected a transition method as the ultimate impact of the new standard has not yet been determined.

On February 25, 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged . ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company is currently evaluating the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

On October 24, 2016, the FASB issued ASU No. 2016-16, *Income Taxes (Topic 740), Intra-Entity Transfers of Assets Other Than Inventory* (ASU 2016-16). Current GAAP prohibits the recognition of current and deferred income taxes for an affiliate asset transfer until the asset has been sold to an outside party. ASU 2016-16 requires an entity to recognize the income tax consequences of an affiliate transfer of an asset other than inventory when the transfer occurs. ASU 2016-16 is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. The amendments will be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the

beginning of the period of adoption. The Company is currently assessing the impact of the standard on its financial statements and has not yet determined its ultimate impact.

On November 17, 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* (ASU 2016-18). ASU 2016-18 eliminates the need to reflect transfers between cash and restricted cash in operating, investing, and financing activities in the statement of cash flows. Upon adoption, the net change in cash and cash equivalents during the period will include amounts generally described as restricted cash or restricted cash equivalents. ASU 2016-18 is effective for fiscal years beginning after December 15, 2017, with early adoption permitted, and will be applied retrospectively to each period presented. The Company does not intend to adopt the guidance early. The adoption of ASU 2016-18 will not have a material impact on the financial statements of the Company.

Affiliate Transactions

Total revenues from all PPAs with affiliates, included in wholesale revenue affiliates on the consolidated statements of income, were $258 million , $219 million , and $153 million for the years ended December 31, 2016 , 2015 , and 2014 , respectively. Included within these revenues were affiliate PPAs accounted for as operating leases, which totaled $109 million in both 2016 and 2015 and $75 million in 2014 .

The Company has an agreement with SCS under which the following services are rendered to the Company at amounts in compliance with FERC regulation: general and design engineering, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, labor, and other services with respect to business and operations, construction management, and transactions associated with the Southern Company system's fleet of generating units. Because the Company has no employees, all employee-related charges are rendered at amounts in compliance with FERC regulation under agreements with SCS. Costs for all of these services from SCS totaled approximately $193 million , $146 million , and $126 million for the years ended December 31, 2016 , 2015 , and 2014 , respectively. Of these costs, approximately $173 million , $138 million , and $125 million for the years ended December 31, 2016 , 2015 , and 2014 , respectively, were charged to other operations and maintenance expenses; the remainder was capitalized to property, plant, and equipment. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company also has several agreements with SCS for transmission services. Transmission services purchased from SCS totaled $11 million in each of the years ended December 31, 2016 and 2015 and $7 million for the year ended December 31, 2014 , and were charged to other operations and maintenance in the consolidated statements of income. All charges were billed to the Company based on the Southern Company Open Access Transmission Tariff as filed with the FERC.

Prior to Southern Company's acquisition of Southern Company Gas, SCS, as agent for the Company, had agreements with various subsidiaries of Southern Company Gas to purchase natural gas. For the period subsequent to Southern Company's acquisition of Southern Company Gas, from July 1, 2016 through December 31, 2016, natural gas purchases made by the Company from Southern Company Gas' subsidiaries were approximately $17 million and are included in fuel expense on the consolidated statements of income.

On September 1, 2016, Southern Company Gas acquired a 50% equity interest in Southern Natural Gas Company, L.L.C. (SNG). Prior to completion of the acquisition, SCS, as agent for the Company, had entered into a long-term interstate natural gas transportation agreement with SNG. The interstate transportation service provided to the Company by SNG pursuant to this agreement is governed by the terms and conditions of SNG's natural gas tariff and is subject to FERC regulation. For the period subsequent to Southern Company Gas' investment in SNG through December 31, 2016, transportation costs under this agreement were approximately $7 million .

In 2016, the Company sold a turbine rotor assembly to Gulf Power for approximately $7 million .

The Company and the traditional electric operating companies may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See "Revenues" herein for additional information.

The Company and the traditional electric operating companies generally settle amounts related to the above transactions on a monthly basis in the month following the performance of such services or the purchase or sale of electricity.

Acquisition Accounting

The Company acquires generation assets as part of its overall growth strategy. For acquisitions that meet the definition of a business, the Company includes the operations in its consolidated financial statements from the respective date of acquisition. The purchase price, including contingent consideration, if any, of each acquisition is allocated based on the fair value of the identifiable assets and liabilities. Assets acquired that do not meet the definition of a business are accounted for as asset acquisitions. The purchase price of each asset acquisition is allocated based on the relative fair value of assets acquired. Any due diligence or transition costs incurred by the Company for successful or potential acquisitions are expensed as incurred. Contingent consideration recognized at the time of each acquisition primarily relates to fixed amounts due to the seller once the facility is successfully placed in service. To the extent there is any contingent consideration with variable payments, the Company fair values the arrangement with changes recorded in net income. See Note 8 for additional information.

Revenues

The Company sells capacity at rates specified under contractual terms for long-term PPAs. These PPAs are generally accounted for as operating leases, non-derivatives, or normal sale derivatives. Capacity revenues from PPAs classified as operating leases are recognized on a straight-line basis over the term of the agreement. Capacity revenues from PPAs classified as non-derivatives or normal sales are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract periods. When multiple contracts exist with the same counterparty, the revenues from each contract are accounted for as separate arrangements. All capacity revenues are included in operating revenues.

The Company may also enter into contracts to sell short-term capacity in the wholesale electricity markets. These sales are generally classified as mark-to-market derivatives and net unrealized gains (losses) on such contracts are recorded in wholesale revenues. See Note 9 for additional information.

Energy revenues and other contingent revenues are recognized in the period the energy is delivered or the service is rendered. Transmission revenues and other fees are recognized as earned as other operating revenues. See "Financial Instruments" herein for additional information.

Significant portions of the Company's revenues have been derived from certain customers pursuant to PPAs. The following table shows the percentage of total revenues for the top three customers:

	2016	2015	2014
Georgia Power	**16.5%**	15.8%	10.1%
Duke Energy Corporation	**7.8%**	8.2%	9.1%
San Diego Gas & Electric Company	**5.7%**	6.1%	2.9%
FPL	**—%**	10.7%	9.7%

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel costs also include emissions allowances which are expensed as the emissions occur.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences.

Under current tax regulation, certain projects related to the construction of renewable facilities are eligible for federal ITCs. The Company estimates eligible costs which, as they relate to acquisitions, may not be finalized until the allocation of the purchase price to assets has been finalized. The Company applies the deferred method to ITCs as opposed to the flow-through method. Under the deferred method the ITCs are recorded as a deferred credit and amortized to income tax expense over the life of the respective asset. Furthermore, the tax basis of the asset is reduced by 50% of the ITCs received, resulting in a net deferred tax asset. The Company has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation. In addition, certain projects are eligible for federal PTCs, which are recorded to income tax expense based on KWH production. Federal ITCs and PTCs available to reduce income taxes payable were not fully utilized during 2016 and will be carried forward and utilized in future years. The Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 for additional information.

Property, Plant, and Equipment

The Company's depreciable property, plant, and equipment consists primarily of generation assets.

Property, plant, and equipment is stated at original cost or acquired fair value. Original cost includes: materials, direct labor incurred by contractors and affiliated companies, and interest capitalized. Interest is capitalized on qualifying projects during the development and construction period. The cost to replace significant items of property defined as retirement units is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred.

When depreciable property, plant, and equipment is retired, or otherwise disposed of in the normal course of business, the applicable cost and accumulated depreciation is removed and a gain or loss is recognized in the consolidated statements of income.

Depreciation

The Company applies component depreciation, where depreciation is computed principally by the straight-line method over the estimated useful life of the asset. Certain generation assets related to natural gas-fired facilities are depreciated on a units-of-production basis, using hours or starts, to better match outage and maintenance costs to the usage of, and revenues from, these assets.

The primary assets in property, plant, and equipment are generating facilities, which generally have estimated useful lives as follows:

Generating facility	Useful life
Natural gas	Up to 45 years
Biomass	Up to 40 years
Solar	Up to 35 years
Wind	Up to 30 years

The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes which could have a material impact on net income in the near term.

Asset Retirement Obligations

Asset retirement obligations (ARO) are computed as the present value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. 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 ARO liability primarily relates to the Company's solar and wind facilities, which are located on long-term land leases requiring the restoration of land at the end of the lease. See Note 2 for acquisitions during 2015 and 2016 which contributed to the increased liability.

Details of the AROs included on the consolidated balance sheets are as follows:

	2016	2015
	(in millions)	
Balance at beginning of year	**$ 21**	$ 13
Liabilities incurred	**42**	7
Accretion	**1**	1
Balance at end of year	**$ 64**	$ 21

Long-Term Service Agreements

The Company has entered into LTSAs for the purpose of securing maintenance support for its natural gas-fired generating facilities. The LTSAs cover all planned inspections on the covered equipment, which generally includes the cost of all labor and materials. The LTSAs also obligate the counterparties to cover the costs of unplanned maintenance on the covered equipment subject to limits and scope specified in each contract.

Payments made under the LTSAs prior to the performance of any planned inspections or unplanned capital maintenance are recorded as a prepayment in noncurrent assets on the consolidated balance sheets and are recorded as payments pursuant to LTSAs and for equipment not yet received in the statements of cash flows. At the time work is performed, which typically occurs during planned inspections, an appropriate amount is transferred from the prepayment to property, plant, and equipment or charged to expense. The receipt of major parts into materials and supplies inventory prior to planned inspections is treated as a noncash transaction for purposes of the statements of cash flows.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets and finite-lived intangibles for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The Company's intangible assets consist primarily of certain PPAs acquired, which are amortized over the term of the PPA. The average term of these PPAs is 19 years . The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If the estimate of undiscounted future cash flows is less than the carrying value of the asset, the fair value of the asset is determined and a loss is recorded.

Amortization expense for acquired PPAs was $10 million for the year ended December 31, 2016 and $3 million for each of the years ended December 31, 2015 and 2014 , and is recorded in operating revenues. The amortization expense for each of the next five years is as follows:

	Amortization Expense
	(in millions)
2017	$ 25
2018	25
2019	25
2020	25
2021	25

Transmission Receivables/Prepayments

As a result of the Company's growth from the acquisition and construction of generating facilities, the Company has transmission receivables and/or prepayments representing the portion of interconnection network and transmission upgrades that will be reimbursed to the Company. Upon completion of the related project, transmission costs are generally reimbursed by the interconnection provider within a five -year period and the receivable/prepayments are reduced as payments or services are received.

Restricted Cash

The use of funds received under credit facilities for Garland, Roserock, and Tranquillity is restricted for construction purposes. In addition, as a result of the Wake Wind acquisition, cash was received and is restricted for final completion payments related to construction. The aggregate amount of restricted cash at December 31, 2016 and 2015 was $13 million and $5 million , respectively, and is included in other deferred charges and assets – non-affiliated.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Materials and supplies include the average cost of generating plant materials and are recorded as inventory when purchased and then expensed or capitalized to property, plant, and equipment, as appropriate, at weighted average cost when installed. In addition, certain major parts are recorded as inventory when acquired and then capitalized at cost when installed to property, plant, and equipment.

Fuel Inventory

Fuel inventory includes the cost of oil, natural gas, biomass, and emissions allowances. The Company maintains oil inventory for use at several natural gas generating units. The Company has contracts in place for natural gas storage to support normal

operations of the Company's natural gas generating units. The Company maintains biomass inventory for use at Plant Nacogdoches. Inventory is maintained using the weighted average cost method. Fuel inventory and emissions allowances are recorded at actual cost when purchased and then expensed at weighted average cost as used. Emissions allowances granted by the EPA are included at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, electricity purchases and sales, and foreign currency exchange rates. All derivative financial instruments are recognized as either assets or liabilities on the consolidated balance sheets (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 8 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions result in the deferral of related gains and losses in AOCI until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded in the financial statement line item where they will eventually settle. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. See Note 9 for additional information regarding derivatives.

Beginning in 2016, the Company offsets the 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, 2016 .

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications of amounts included in net income.

Variable Interest Entities

The primary beneficiary of a variable interest entity (VIE) is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

The Company has certain wholly-owned subsidiaries that are determined to be VIEs. The Company is considered the primary beneficiary of these VIEs because it controls the most significant activities of the VIEs, including operating and maintaining the respective assets, and has the obligation to absorb expected losses of these VIEs to the extent of its equity interests.

2. ACQUISITIONS

During 2016 and 2015 , in accordance with its overall growth strategy, the Company or one of its wholly-owned subsidiaries, SRP and SRE, acquired or contracted to acquire the projects discussed below. Also, on March 29, 2016, the Company acquired an additional 15% interest in Desert Stateline, 51% of which was initially acquired in August 2015. As a result, the Company and the class B member are now entitled to 66% and 34% , respectively, of all cash distributions from Desert Stateline. In addition, the Company will continue to be entitled to substantially all of the federal tax benefits with respect to the transaction. Acquisition-related costs were expensed as incurred and were not material for any of the years presented.

NOTES (continued)
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The following table presents the Company's acquisitions during and subsequent to the year ended December 31, 2016.

Project Facility	Resource	Seller; Acquisition Date	Approximate Nameplate Capacity (*MW*)	Location	Percentage Ownership	Actual/Expected COD	PPA Contract Period
Acquisitions During the Year Ended December 31, 2016							
Boulder 1	Solar	SunPower November 16, 2016	100	Clark County, NV	51% [(a)]	December 2016	20 years
Calipatria	Solar	Solar Frontier Americas Holding LLC February 11, 2016	20	Imperial County, CA	90% [(b)]	February 2016	20 years
East Pecos	Solar	First Solar, Inc. March 4, 2016	120	Pecos County, TX	100%	March 2017	15 years
Grant Plains	Wind	Apex Clean Energy Holdings, LLC August 26, 2016	147	Grant County, OK	100%	December 2016	20 years and 12 years [(c)]
Grant Wind	Wind	Apex Clean Energy Holdings, LLC April 7, 2016	151	Grant County, OK	100%	April 2016	20 years
Henrietta	Solar	SunPower July 1, 2016	102	Kings County, CA	51% [(a)]	July 2016	20 years
Lamesa	Solar	RES America Developments Inc. July 1, 2016	102	Dawson County, TX	100%	Second quarter 2017	15 years
Mankato [(d)]	Natural Gas	Calpine Corporation October 26, 2016	375	Mankato, MN	100%	N/A [(e)]	10 years
Passadumkeag	Wind	Quantum Utility Generation, LLC June 30, 2016	42	Penobscot County, ME	100%	July 2016	15 years
Rutherford	Solar	Cypress Creek Renewables, LLC July 1, 2016	74	Rutherford County, NC	90% [(b)]	December 2016	15 years
Salt Fork	Wind	EDF Renewable Energy, Inc. December 1, 2016	174	Donley and Gray Counties, TX	100%	December 2016	14 years and 12 years
Tyler Bluff	Wind	EDF Renewable Energy, Inc. December 21, 2016	125	Cooke County, TX	100%	December 2016	12 years
Wake Wind	Wind	Invenergy October 26, 2016	257	Floyd and Crosby Counties, TX	90.1% [(f)]	October 2016	12 years
Acquisitions Subsequent to December 31, 2016							
Bethel	Wind	Invenergy January 6, 2017	276	Castro County, TX	100%	January 2017	12 years

(a) The Company owns 100% of the class A membership interests and a wholly-owned subsidiary of the seller owns 100% of the class B membership interests. The Company and the class B member are entitled to 51% and 49% , respectively, of all cash distributions from the project. In addition, the Company is entitled to substantially all of the federal tax benefits with respect to the transaction.
(b) The Company owns 90% , with the minority owner, TRE, owning 10% .
(c) In addition to the 20 -year and 12 -year PPAs, the facility has a 10 -year contract with Allianz Risk Transfer (Bermuda) Ltd.
(d) Under the terms of the remaining 10 -year PPA and the 20 -year expansion PPA, approximately $408 million of assets, primarily related to property, plant, and equipment, are subject to lien at December 31, 2016.
(e) The acquisition included a fully operational 375 -MW natural gas-fired combined-cycle facility.
(f) The Company owns 90.1% , with the minority owner, Invenergy, owning 9.9% .

Acquisitions During the Year Ended December 31, 2016

The Company's aggregate purchase price for acquisitions during the year ended December 31, 2016 was approximately $2.3 billion . Including the minority owner TRE's 10% ownership interest in Calipatria and Rutherford, SunPower's 49% ownership interest in Boulder 1 and Henrietta, along with the assumption of $217 million in construction debt (non-recourse to the Company), and Invenergy's 9.9% ownership interest in Wake Wind, the total aggregate purchase price is approximately $2.6 billion for the project facilities acquired during the year ended December 31, 2016 . The allocations of the purchase price to

NOTES (continued)
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individual assets have not been finalized, except for Calipatria, East Pecos, Lamesa, and Rutherford, which were finalized with no changes to amounts originally reported. The fair values of the assets and liabilities acquired through the business combinations were recorded as follows:

		2016
		(in millions)
CWIP	$	2,354
Property, plant, and equipment		302
Intangible assets [(a)]		128
Other assets		52
Accounts payable		(16)
Debt		(217)
Total purchase price	$	2,603
Funded by:		
The Company [(b)] [(c)]	$	2,345
Noncontrolling interests [(d)] [(e)]		258
Total purchase price	$	2,603

(a) Intangible assets consist of acquired PPAs that will be amortized over 10 and 20 -year terms. The estimated amortization for future periods is approximately $9 million per year. See Note 1 for additional information.
(b) At December 31, 2016 , $461 million is included in acquisitions payable on the consolidated balance sheets.
(c) Includes approximately $281 million of contingent consideration, of which $67 million remains payable at December 31, 2016.
(d) Includes approximately $51 million of non-cash contributions recorded as capital contributions from noncontrolling interests in the consolidated statements of stockholders' equity.
(e) Includes approximately $142 million of contingent consideration, all of which had been paid at December 31, 2016 by the noncontrolling interests.

The aggregate amount of revenue recognized by the Company related to the acquisitions during 2016, included in the consolidated statement of income for 2016 , is $37 million . The amount of net income, excluding impacts of ITCs and PTCs, attributable to the Company related to the acquisitions during 2016 included in the consolidated statement of income is immaterial.

The solar and wind acquisitions did not have operating revenues or net income prior to the completion of construction and the generating facility being placed in service; therefore, supplemental pro forma information as if these acquisitions occurred as of the beginning of 2016 , and for the comparable 2015 year, is not meaningful and has been omitted. However, the Mankato acquisition is an operating facility and unaudited supplemental pro forma information, as though the acquisition occurred as of the beginning of 2016 and for the comparable 2015 year, is as follows:

		2016		2015
		(in millions)		
Revenues	$	40	$	39
Net income	$	14	$	11

These unaudited pro forma results are for comparative purposes only and may not be indicative of the results that would have occurred had this acquisition been completed on January 1, 2015 or the results that may be attained in the future.

NOTES (continued)
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The following table presents the Company's acquisitions for the year ended December 31, 2015 . During the year ended December 31, 2016 , the fair values of assets and liabilities acquired for all projects listed below were finalized with no changes to amounts originally reported.

Project Facility	Resource	Seller; Acquisition Date	Approximate Nameplate Capacity (*MW*)	Location	Percentage Ownership	Actual COD	PPA Contract Period
Acquisitions for the Year Ended December 31, 2015							
Desert Stateline	Solar	First Solar August 31, 2015	299 (a)	San Bernardino County, CA	51% (b)	From December 2015 to July 2016	20 years
Garland and Garland A	Solar	Recurrent December 17, 2015	205	Kern County, CA	51% (b)	October and August 2016	15 years and 20 years
Kay Wind	Wind	Apex Clean Energy Holdings, LLC December 11, 2015	299	Kay County, OK	100%	December 2015	20 years
Lost Hills Blackwell	Solar	First Solar April 15, 2015	33	Kern County, CA	51% (b)	April 2015	29 years
Morelos	Solar	Solar Frontier Americas Holding, LLC October 22, 2015	15	Kern County, CA	90% (c)	November 2015	20 years
North Star	Solar	First Solar April 30, 2015	61	Fresno County, CA	51% (b)	June 2015	20 years
Roserock	Solar	Recurrent November 23, 2015	160	Pecos County, TX	51% (b)	November 2016	20 years
Tranquillity	Solar	Recurrent August 28, 2015	205	Fresno County, CA	51% (b)	July 2016	18 years

(a) The facility has a total of 299 MWs, of which 110 MWs were placed in service in the fourth quarter 2015 and the remainder by July 2016.
(b) The Company owns 100% of the class A membership interests and a wholly-owned subsidiary of the seller owns 100% of the class B membership interests. The Company and the class B member are entitled to 51% and 49% , respectively, of all cash distributions from the project. In addition, the Company is entitled to substantially all of the federal tax benefits with respect to the transaction.
(c) The Company owns 90% , with the minority owner, TRE, owning 10% .

Acquisitions During the Year Ended December 31, 2015

The Company's aggregate purchase price for the project facilities acquired during the year ended December 31, 2015 was approximately $1.4 billion . Including the minority owner TRE's 10% ownership interest in Morelos, First Solar's 49% ownership interest in Desert Stateline, Lost Hills Blackwell, and North Star, and Recurrent's 49% ownership interest in Garland, Garland A, Roserock, and Tranquillity, the total aggregate purchase price was approximately $1.9 billion for the project facilities acquired during the year ended December 31, 2015 .

The fair values of the assets and liabilities acquired through the business combinations were recorded as follows:

	2015
	(in millions)
CWIP	$ 1,367
Property, plant, and equipment	315
Intangible assets [(a)]	274
Other assets	64
Accounts payable	(89)
Total purchase price	$ 1,931
Funded by:	
The Company [(b)]	$ 1,440
Noncontrolling interests [(c)] [(d)]	491
Total purchase price	$ 1,931

(a) Intangible assets consist of acquired PPAs that will be amortized over 20 -year terms. The estimated amortization for future periods is approximately $14 million per year. See Note 1 under "Impairment of Long-Lived Assets and Intangibles" for additional information.
(b) Includes approximately $195 million of contingent consideration, all of which had been paid at December 31, 2016 .
(c) Includes approximately $227 million of non-cash contributions recorded as capital contributions from noncontrolling interests in the consolidated statements of stockholders' equity.
(d) Includes approximately $76 million of contingent consideration, all of which had been paid at December 31, 2016 by the noncontrolling interests.

Construction Projects

Construction Projects Completed

During 2016 , in accordance with its overall growth strategy, the Company completed construction of, and placed in service, the projects set forth in the table below. Total costs of construction incurred for these projects were $3.2 billion .

Solar Facility	Seller	Approximate Nameplate Capacity (*MW*)	Location	Actual COD	PPA Contract Period
Butler	CERSM, LLC and Community Energy, Inc.	103	Taylor County, GA	December 2016	30 years [(a)]
Butler Solar Farm	Strata Solar Development, LLC	22	Taylor County, GA	February 2016	20 years [(a)]
Desert Stateline	First Solar Development, LLC	299 [(b)]	San Bernardino County, CA	From December 2015 to July 2016	20 years
Garland	Recurrent	185	Kern County, CA	October 2016	15 years
Garland A	Recurrent	20	Kern County, CA	August 2016	20 years
Pawpaw	Longview Solar, LLC	30	Taylor County, GA	March 2016	30 years
Roserock [(c)]	Recurrent	160	Pecos County, TX	November 2016	20 years
Sandhills	N/A	146	Taylor County, GA	October 2016	25 years
Tranquillity	Recurrent	205	Fresno County, CA	July 2016	18 years

(a) Affiliate PPA approved by the FERC.
(b) The facility has a total of 299 MWs, of which 110 MWs were placed in service in the fourth quarter 2015 and the remainder by July 2016.
(c) Prior to placing the Roserock facility in service, certain solar panels were damaged. While the facility is currently generating energy as expected, the Company is pursuing remedies under its insurance policies and other contracts to repair or replace these solar panels.

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Construction Projects in Progress

At December 31, 2016 , the Company continued construction of the East Pecos and Lamesa solar facilities that were acquired in 2016 . In addition, as part of the Company's acquisition of Mankato in 2016 , the Company commenced construction of an additional 345 -MW expansion, which is fully contracted under a new 20 -year PPA. Total aggregate construction costs, excluding the acquisition costs, are expected to be $530 million to $590 million for East Pecos, Lamesa, and Mankato. At December 31, 2016 , the construction costs totaled $386 million and are included in CWIP. The ultimate outcome of these matters cannot be determined at this time.

The following table presents the Company's construction projects in progress as of December 31, 2016:

Project Facility	Resource	Approximate Nameplate Capacity (*MW*)	Location	Actual/Expected COD	PPA Contract Period
East Pecos	Solar	120	Pecos County, TX	March 2017	15 years
Lamesa	Solar	102	Dawson County, TX	Second quarter 2017	15 years
Mankato	Natural Gas	345	Mankato, MN	Second quarter 2019	20 years

Development Projects

In December 2016 , as part of the Company's renewable development strategy, SRP entered into a joint development agreement with Renewable Energy Systems Americas, Inc. to develop and construct approximately 3,000 MWs across 10 wind projects expected to be placed in service between 2018 and 2020 . Also in December 2016, the Company signed agreements and made payments to purchase wind turbine equipment from Siemens Wind Power, Inc. and Vestas-American Wind Technology, Inc. to be used for construction of the facilities. Once these wind projects reach commercial operations, they are expected to qualify for 100% PTCs. The ultimate outcome of these matters cannot be determined at this time.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against the Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

FERC Matters

The Company and certain of its generation subsidiaries are subject to regulation by the FERC. 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 and the Company filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric operating companies' and the Company'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 and the Company to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies and the Company filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.

On December 9, 2016, the traditional electric operating companies and the Company 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' and the Company's potential to exert market power in certain areas served by the traditional electric

operating companies and in some adjacent areas. The traditional electric operating companies and the Company expect to make a compliance filing within 30 days accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

The ultimate outcome of these matters cannot be determined at this time.

4. JOINT OWNERSHIP AGREEMENTS

The Company is a 65% owner of Plant Stanton A, a natural gas-fired combined-cycle unit with a nameplate capacity of 659 MWs. The unit is co-owned by the Orlando Utilities Commission (28%), the Florida Municipal Power Agency (3.5%), and the Kissimmee Utility Authority (3.5%). The Company has a service agreement with SCS whereby SCS is responsible for the operation and maintenance of Plant Stanton A. As of December 31, 2016 , $155 million was recorded in plant in service with associated accumulated depreciation of $58 million . These amounts represent the Company's share of total plant assets and each owner is responsible for providing its own financing. The Company's proportionate share of Plant Stanton A's operating expense is included in the corresponding operating expenses in the consolidated statements of income.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and various state income tax returns, some of which are combined, unitary, or consolidated. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2016	2015	2014
		(in millions)	
Federal —			
Current (*)	**$ 928**	$ 12	$ 179
Deferred (*)	**(1,098)**	10	(166)
	(170)	22	13
State —			
Current	**(60)**	(32)	(14)
Deferred	**35**	31	(2)
	(25)	(1)	(16)
Total	**$ (195)**	$ 21	$ (3)

(*) ITCs and PTCs generated in the current tax year and carried forward from prior tax years that cannot be utilized in the current tax year are reclassified from current to deferred taxes in federal income tax expense above. ITCs and PTCs reclassified in this manner include $1.13 billion for 2016 , $246 million for 2015 , and $305 million for 2014. These ITCs and PTCs are included in the following table of temporary differences as unrealized tax credits.

NOTES (continued)
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The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2016	2015
Deferred tax liabilities —		
Accelerated depreciation and other property basis differences	$ 2,440	$ 1,364
Levelized capacity revenues	28	22
Other	27	7
Total deferred income tax liabilities	2,495	1,393
Deferred tax assets —		
Federal effect of state deferred taxes	53	40
Basis difference on ITCs	292	149
Alternative minimum tax carryforward	15	15
Unrealized tax credits	1,685	551
Federal net operating loss (NOL)	808	9
Deferred state tax assets	60	13
Other partnership basis differences	16	3
Other	8	14
Total deferred income tax assets	2,937	794
Valuation Allowance	—	(2)
Net deferred income tax assets	2,937	792
Total deferred income tax asset (liability)	$ 442	$ (601)
Recognized in the consolidated balance sheets:		
Accumulated deferred income taxes – assets	$ 594	$ —
Accumulated deferred income taxes – liability	$ (152)	$ (601)

Deferred tax liabilities are primarily the result of property-related timing differences. The application of bonus depreciation provisions in current tax law significantly increased deferred tax liabilities related to accelerated depreciation.

Deferred tax assets consist primarily of timing differences related to the carryforward of unrealized federal ITCs, PTCs, net operating loss, and net basis differences on federal ITCs.

Tax Credit Carryforwards

At December 31, 2016, the Company had federal ITC and PTC carryforwards, which are expected to result in $1.7 billion of federal income tax benefits. The federal ITC carryforwards begin expiring in 2032 but are expected to be fully utilized by 2022. The PTC carryforwards begin expiring in 2036 but are expected to be fully utilized by 2022. The acquisition of additional renewable projects and carrying back the federal NOL, as well as potential tax reform legislation, could further delay the utilization of existing tax credit carryforwards. The ultimate outcome of these matters cannot be determined at this time.

Net Operating Loss

Southern Company is expecting a consolidated federal net operating loss of approximately $2.8 billion for income tax purposes for the 2016 tax year. Portions of the NOL are expected to be carried back to prior tax years and forward to future tax years. The ultimate outcome of this matter cannot be determined at this time.

NOTES (continued)
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The Company had state NOL carryforwards of $1.0 billion and $225 million at December 31, 2016 and December 31, 2015, respectively, which will expire from 2029 to 2035. These carryforwards resulted in deferred tax assets of $40 million as of December 31, 2016 and $8 million as of December 31, 2015. The state NOL carryforwards by jurisdiction were as follows:

Jurisdiction	NOL Carryforwards	Net State Income Tax Benefit	Tax Year NOL Expires
	(in millions)		
Oklahoma	$ 838	$ 32	2035
Florida	185	7	2033
Other states	7	1	2029 through 2035
Balance at year end	$ 1,030	$ 40	

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2016	2015	2014
Federal statutory rate	**35.0 %**	35.0 %	35.0 %
State income tax, net of federal deduction	**(9.1)**	(0.3)	(6.0)
Amortization of ITC	**(20.6)**	(5.0)	(4.3)
ITC basis difference	**(89.0)**	(21.5)	(27.7)
Production tax credits	**(23.3)**	(0.6)	—
Noncontrolling interests	**(6.2)**	(1.7)	(0.3)
Other	**4.6**	2.5	1.4
Effective income tax rate (benefit)	**(108.6)%**	8.4 %	(1.9)%

The Company's effective tax rate decreased in 2016 and increased in 2015 primarily due to changes in federal ITCs.

The Company's deferred federal ITCs are amortized to income tax expense over the life of the respective asset. ITCs amortized in this manner amounted to $37 million in 2016, $19 million in 2015, and $11 million in 2014. Also, the Company received cash related to federal ITCs under the renewable energy incentives of $162 million and $74 million for the years ended December 31, 2015 and 2014, respectively. No cash was received related to these incentives in 2016. Furthermore, the tax basis of the asset is reduced by 50% of the ITCs received, resulting in a net deferred tax asset. The Company has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation. The tax benefit of the related basis differences reduced income tax expense by $173 million in 2016, $54 million in 2015, and $48 million in 2014. The tax benefit of PTCs reduced income tax expense by $42 million in 2016 and $1 million in 2015. See "Unrecognized Tax Benefits" below for further information.

Unrecognized Tax Benefits

Changes during the year in unrecognized tax benefits were as follows:

	2016	2015	2014
		(in millions)	
Balance at beginning of year	**$ 8**	$ 5	$ 2
Tax positions increase from current periods	**17**	9	5
Tax positions decrease from prior periods	**(8)**	(6)	(2)
Balance at end of year	**$ 17**	$ 8	$ 5

The increase in unrecognized tax benefits from current periods for 2016, 2015, and 2014, and the decrease from prior periods in 2016 and 2015, primarily relate to federal income tax benefits from deferred ITCs and would all impact the Company's effective tax rate, if recognized. The impact on the effective tax rate is determined based on the amount of ITCs which are uncertain. If these tax positions are not able to be recognized due to a federal audit adjustment in the amount that has been estimated, the amount of tax credit carryforwards discussed above would be reduced by approximately $92 million .

The Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial for all periods presented. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months . The settlement of federal and state audits could impact the balances. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013, 2014, and 2015 federal income tax returns and has received partial acceptance letters from the IRS; however, the IRS has not finalized its audits. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

6. FINANCING

Southern Power Company's senior notes, bank term loans, commercial paper, and credit facility are unsecured senior indebtedness, which rank equally with all other unsecured and unsubordinated debt of Southern Power Compan y. The Company's subsidiaries are not issuers, borrowers, or obligors, as applicable, under the senior notes, bank term loans, commercial paper, or the Facility (as defined herein). The se nior notes, bank term loans, commercial paper, and the Facility are effectively subordinated to any future secured debt and any potential claims of creditors of the Company's subsidiaries. As of December 31, 2016 , the Company had no secured debt other than indebtedness outstanding under the subsidiary project credit facilities discussed below.

Securities Due Within One Year

At December 31, 2016 , the Company had a $60 million bank loan and $500 million of senior notes due within one year. At December 31, 2015 , the Company had a $400 million bank loan due within one year. In addition, the Company classified as due within one year approximately $1 million and $3 million of long-term notes payable to TRE at December 31, 2016 and 2015, respectively.

Maturities of long-term debt are as follows:

		December 31, 2016
		(in millions)
2017	$	561
2018		670
2019		600
2020		300
2021		300

Senior Notes

In June 2016, the Company issued € 600 million aggregate principal amount of Series 2016A 1.00% Senior Notes due June 20, 2022 and € 500 million aggregate principal amount of Series 2016B 1.85% Senior Notes due June 20, 2026. The net proceeds are being allocated to renewable energy generation projects. The Company's obligations under its euro-denominated fixed-rate notes were effectively converted to fixed-rate U.S. dollars at issuance through foreign currency swaps, mitigating foreign currency exchange rate risk associated with the interest and principal payments. See Note 9 under "Foreign Currency Derivatives" for additional information.

In September 2016, the Company issued $290 million aggregate principal amount of Series 2016C 2.75% Senior Notes due September 20, 2023. The proceeds were used for general corporate purposes, including the Company's growth strategy and continuous construction program, as well as repayment of amounts outstanding under the subsidiary project credit facilities, discussed below.

In November 2016, the Company issued $600 million aggregate principal amount of Series 2016D 1.95% Senior Notes due December 15, 2019, $300 million aggregate principal amount of Series 2016E 2.50% Senior Notes due December 15, 2021, and $400 million aggregate principal amount of Series 2016F 4.95% Senior Notes due December 15, 2046. The net proceeds of the Series 2016D and the Series 2016E Senior Notes are being allocated to renewable energy generation projects. The proceeds of the Series 2016F Senior Notes were used to redeem, in December 2016, all of the $200 million aggregate principal amount of the Company's Series E 6.375% Senior Notes due November 15, 2036 and to repay outstanding short-term indebtedness.

At December 31, 2016 and 2015 , the Company had $5.3 billion and $2.7 billion of senior notes outstanding, respectively, which included senior notes due within one year.

Other Long-Term Notes

During 2016 , the Company repaid $6 million and issued $5 million of long-term notes payable to TRE due 2035 through 2036 related to the financing of Calipatria, Morelos, and Rutherford. At December 31, 2016 and 2015 , the Company had $15 million and $13 million , respectively, of long-term notes payable to TRE.

In September 2016, the Company repaid $80 million of an outstanding $400 million floating rate bank term loan and extended the maturity date of the remaining $320 million from September 2016 to September 2018. In addition, the Company entered into a $60 million aggregate principal amount floating rate bank term loan bearing interest based on one-month LIBOR due September 2017, which is included in securities due within one year on the consolidated balance sheets. The proceeds were used to repay existing indebtedness and for other general corporate purposes.

Each of these bank term loan agreements has a covenant that limits debt levels to 65% of total capitalization, as defined by the agreements. For purposes of this definition, debt excludes any project debt incurred by certain subsidiaries of the Company to the extent such debt is non-recourse to the Company, and capitalization excludes the capital stock or other equity attributable to such subsidiary. At December 31, 2016 , the Company was in compliance with its debt limits.

Asset Subject to Lien

During 2016, in accordance with its overall growth strategy, the Company acquired the Mankato project. Under the terms of the remaining 10 -year PPA and the 20 -year expansion PPA, approximately $408 million of assets, primarily related to property, plant, and equipment, are subject to lien at December 31, 2016. See Note 2 for additional information.

Bank Credit Arrangements

Company Credit Facilities

At December 31, 2016 , the Company had a committed credit facility (Facility) of $600 million expiring in 2020. Proceeds from the Facility may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program. As of December 31, 2016 , the total amount available under the Facility was $522 million . As of December 31, 2015 , the total amount available under the Facility was $566 million . The amounts outstanding as of December 31, 2016 and 2015 reflect $78 million and $34 million in letters of credit, respectively. The Facility does not contain a material adverse change clause at the time of borrowing. Subject to applicable market conditions, the Company expects to renew or replace the Facility, as needed, prior to expiration. In connection therewith, the Company may extend the maturity date and/or increase or decrease the lending commitment thereunder.

The Company is required to pay a commitment fee on the unused balance of the Facility. This fee is less than 1/4 of 1%. The Facility contains a covenant that limits the ratio of debt to capitalization (each as defined in the Facility) to a maximum of 65% . For purposes of this definition, debt excludes any project debt incurred by certain subsidiaries of the Company to the extent such debt is non-recourse to the Company, and capitalization excludes the capital stock or other equity attributable to such subsidiary. At December 31, 2016 , the Company was in compliance with its debt limits.

In December 2016, the Company entered into an agreement for a $120 million continuing letter of credit facility for standby letters of credit expiring in 2019. At December 31, 2016, the total amount available under the facility was $82 million . The Company's subsidiaries are not parties to the facility.

Commercial Paper Program

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes. There was no commercial paper outstanding as of December 31, 2016 and 2015 .

Subsidiary Project Credit Facilities

In connection with the construction of solar facilities by RE Tranquillity LLC, RE Roserock LLC, and RE Garland Holdings LLC, indirect subsidiaries of the Company, each subsidiary entered into separate credit agreements (Project Credit Facilities), which were non-recourse to the Company (other than the subsidiary party to the agreement). Each Project Credit Facility provided (a) a senior secured construction loan credit facility, (b) a senior secured bridge loan facility, and (c) a senior secured letter of credit facility that was secured by the membership interests of the respective project company, with proceeds directed to finance project costs related to the respective solar facilities. Each Project Credit Facility was secured by the assets of the applicable project subsidiary and membership interests of the applicable project subsidiary. The Tranquillity and Garland Project Credit Facilities were fully repaid on October 14, 2016 and December 29, 2016, respectively. The table below summarizes the Roserock Project Credit Facility as of December 31, 2016, which was extended to and fully repaid on January 31, 2017.

Project	Construction Loan Facility	Bridge Loan Facility	Total Loan Facility	Loan Facility Undrawn	Letter of Credit Facility	Letter of Credit Facility Undrawn
				(in millions)		
Roserock	$ 63	$ 180	$ 243	$ 34	$ 23	$ 16

The Project Credit Facilities had total amounts outstanding of $209 million and $137 million , at a weighted average interest rate of 2.1% and 2.0% , as of December 31, 2016 and 2015, respectively.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

7. COMMITMENTS

Fuel Agreements

SCS, as agent for the Company and the traditional electric operating companies, has entered into various fuel transportation and procurement agreements to supply a portion of the fuel (primarily natural gas) requirements for the operating facilities which are not recognized on the Company's consolidated balance sheets. In 2016 , 2015 , and 2014 , the Company incurred fuel expense of $456 million , $441 million , and $596 million , respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and Southern Company's traditional electric operating companies. Under these agreements, each of the traditional electric operating companies and the Company may be jointly and severally liable. Southern Company has entered into keep-well agreements with each of the traditional electric operating companies to ensure they will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of the Company as a contracting party under these agreements.

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total rent expense was $22 million , $7 million , and $4 million for 2016 , 2015 , and 2014 , respectively. These amounts include contingent rent expense related to land leases based on escalation in the Consumer Price Index for All Urban Consumers. The Company includes step rents, escalations, lease concessions, and lease extensions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term. As of December 31, 2016 , estimated minimum lease payments under operating leases were $18 million in 2017 , $19 million in 2018 , $20 million in each of 2019 , 2020 , and 2021 , and $762 million in 2022 and thereafter. The majority of the committed future expenditures are related to land leases for solar and wind facilities.

Redeemable Noncontrolling Interests

See Note 10.

8. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is

minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2016 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

	Fair Value Measurements Using			
As of December 31, 2016:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
	(in millions)			
Assets:				
Energy-related derivatives	$ —	$ 21	$ —	$ 21
Interest rate derivatives	—	1	—	1
Cash equivalents	628	—	—	628
Total	$ 628	$ 22	$ —	$ 650
Liabilities:				
Energy-related derivatives	$ —	$ 5	$ —	$ 5
Foreign currency derivatives	—	58	—	58
Contingent consideration	—	—	18	18
Total	$ —	$ 63	$ 18	$ 81

As of December 31, 2015 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

	Fair Value Measurements Using			
As of December 31, 2015:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
	(in millions)			
Assets:				
Energy-related derivatives	$ —	$ 4	$ —	$ 4
Interest rate derivatives	—	3	—	3
Cash equivalents	511	—	—	511
Total	$ 511	$ 7	$ —	$ 518
Liabilities:				
Energy-related derivatives	$ —	$ 3	$ —	$ 3

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 fair value of cross-currency swaps reflects the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future foreign currency exchange rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and discount rates. The interest rate derivatives and cross-currency swaps are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 9 for additional information on how these derivatives are used.

The Company has contingent payment obligations related to certain acquisitions whereby the Company is obligated to pay generation-based payments to the seller over a 10 -year period beginning at the commercial operation date. The obligation is categorized as Level 3 under Fair Value Measurements as the fair value is determined using significant unobservable inputs for the forecasted facility generation in MW-hours, as well as other inputs such as a fixed dollar amount per MW-hour, and a discount rate, and is evaluated periodically. The fair value of contingent consideration reflects the net present value of expected payments and any change arising from forecasted generation is expected to be immaterial.

As of December 31, 2016 and 2015 , other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt, including securities due within one year:		
2016	**$ 5,628**	**$ 5,691**
2015	$ 3,122	$ 3,117

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates available to the Company.

9. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk, and occasionally foreign currency exchange 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 consolidated balance sheets as either assets or liabilities and are presented on a net basis. See Note 8 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities. The cash impacts of settled foreign currency derivatives are classified as operating or financing activities to correspond with classification of the hedged interest or principal, respectively. See Note 1 under "Financial Instruments" for additional information.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. The Company has limited exposure to market volatility in energy-related commodity prices because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, the Company has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of uncontracted generating capacity.

Energy-related derivative contracts are accounted for under one of two methods:

- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges which are used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the consolidated statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the consolidated statements of income as incurred.

NOTES (continued)
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Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2016 , the net volume of energy-related derivative contracts for natural gas positions totaled 27 million mmBtu, all of which expire in 2017 , which is the longest hedge date. At December 31, 2016 , the net volume of energy-related derivative contracts for power positions was 6.1 million MWs, all of which expire in 2017 , which is the longest hedge date.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 3 million mmBtu.

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to earnings for the next 12 -month period ending December 31, 2017 is $14 million .

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. Fair value gains or losses on derivatives that are not designated or fail to qualify as hedges are recognized in the consolidated statements of income as incurred.

At December 31, 2016 , the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2016
	(in millions)				*(in millions)*
Derivatives not Designated as Hedges	$ 47 (a.b)	3-month LIBOR	2.21%	January 2017 (c)	$ 1

(a) Swaption at RE Roserock LLC.
(b) Amortizing notional amount.
(c) Represents the mandatory settlement date. Settlement amount was based on a 15 -year amortizing swap.

The Company does not have any deferred gains and losses in AOCI related to past cash flow hedges that are expected to be amortized into earnings through 2017. As such, the Company does not expect any pre-tax gains (losses) to be reclassified from AOCI to interest expense for the 12 -month period ending December 31, 2017 .

Foreign Currency Derivatives

The Company may also enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates, such as that arising from the issuance of debt denominated in a currency other than U.S. dollars. Derivatives related to 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 that the hedged transactions affect earnings, including foreign currency gains or losses arising from changes in the U.S. currency exchange rates. Any ineffectiveness is recorded directly to earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

NOTES (continued)
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At December 31, 2016 , the following foreign currency derivatives were outstanding:

	Pay Notional	Pay Rate	Receive Notional	Receive Rate	Hedge Maturity Date	Fair Value Gain (Loss) at December 31, 2016
	(in millions)		*(in millions)*			*(in millions)*
Cash Flow Hedges of Existing Debt						
	$ 677	2.95%	€ 600	1.00%	June 2022	$ (34)
	564	3.78%	500	1.85%	June 2026	(24)
Total	$ 1,241		€ 1,100			$ (58)

The estimated pre-tax gains (losses) that will be reclassified from accumulated OCI to earnings for the next 12 -month period ending December 31, 2017 total $(25) million .

Derivative Financial Statement Presentation and Amounts

The Company enters into energy-related and interest rate derivative contracts that may contain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. At December 31, 2016, fair value amounts of derivative assets and liabilities on the consolidated balance sheets are presented net to the extent that there are netting arrangements or similar agreements with counterparties. At December 31, 2015, the fair value amounts of derivative instruments were presented gross on the consolidated balance sheets.

At December 31, 2016 and 2015, the fair value of energy-related, interest rate, and foreign currency derivatives reflected in the consolidated balance sheets is as follows:

	2016		2015	
Derivative Category and Balance Sheet Location	**Assets**	**Liabilities**	Assets	Liabilities
		(in millions)		
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Energy-related derivatives:				
Other current assets/Other current liabilities	**$ 18**	**$ 4**	$ 3	$ 2
Foreign currency derivatives:				
Other current assets/Other current liabilities	**—**	**25**	—	—
Other deferred charges and assets/Other deferred credits and liabilities	**—**	**33**	—	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges	**$ 18**	**$ 62**	$ 3	$ 2
Derivatives not designated as hedging instruments				
Energy-related derivatives:				
Other current assets/Other current liabilities	**$ 3**	**$ 1**	$ 1	$ 1
Interest rate derivatives:				
Other current assets/Other current liabilities	**1**	**—**	3	—
Total derivatives not designated as hedging instruments	**$ 4**	**$ 1**	$ 4	$ 1
Gross amounts of recognized assets and liabilities	**$ 22**	**$ 63**	$ 7	$ 3
Gross amounts offset	**$ (5)**	**$ (5)**	$ (1)	$ (1)
Net amounts of assets and liabilities (*)	**$ 17**	**$ 58**	$ 6	$ 2

(*) At December 31, 2015, the fair value amounts for derivative contracts subject to netting arrangements were presented gross on the consolidated balance sheet.

NOTES (continued)
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For the years ended December 31, 2016 , 2015 , and 2014 , the pre-tax effects of energy-related, interest rate, and foreign currency derivatives designated as cash flow hedging instruments on the consolidated statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from AOCI into Income (Effective Portion)			
Derivative Category	**2016**	2015	2014	**Statements of Income Location**	**2016**	2015	2014
		(in millions)				*(in millions)*	
Energy-related derivatives	**$ 14**	$ —	$ —	Amortization	**$ 2**	$ —	$ —
Interest rate derivatives	**—**	—	—	Interest expense, net of amounts capitalized	**(1)**	(1)	(1)
Foreign currency derivatives	**(58)**	—	—	Interest expense, net of amounts capitalized	**(13)**	—	—
				Other income (expense), net	**(82)**	—	—
Total	**$ (44)**	$ —	$ —		**$ (94)**	$ (1)	$ (1)

There was no material ineffectiveness recorded in earnings for any period presented.

The pre-tax effects of energy-related derivatives and interest rate derivatives not designated as hedging instruments on the Company's consolidated statements of income were not material for any year presented.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2016 , there was no collateral posted with the Company's derivative counterparties.

At December 31, 2016 , the fair value of derivative liabilities with contingent features, including certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade because of joint and several liability features underlying these derivatives, was immaterial.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

10. NONCONTROLLING INTERESTS

TRE can require the Company to purchase its redeemable noncontrolling interests in STR, which owns various solar facilities contracted under long-term PPAs, at fair market value pursuant to the partnership agreement, and SunPower can require the Company to purchase its redeemable noncontrolling interest at fair market value until April 30, 2017. As of December 31, 2016, the carrying amounts of STR's and SunPower's noncontrolling interests were $50 million and $114 million , respectively.

NOTES (continued)
Southern Power Company and Subsidiary Companies 2016 Annual Report

The following table presents the changes in redeemable noncontrolling interests for the years ended December 31:

	2016	2015	2014
		(in millions)	
Beginning balance	**$ 43**	$ 39	$ 29
Net income attributable to redeemable noncontrolling interests	**4**	2	4
Distributions to redeemable noncontrolling interests	**(1)**	—	(1)
Capital contributions from redeemable noncontrolling interests	**118**	2	7
Ending balance	**$ 164**	$ 43	$ 39

The following table presents the attribution of net income (loss) to the Company and the noncontrolling interests for the years ended December 31:

	2016	2015	2014
		(in millions)	
Net income	**$ 374**	$ 229	$ 175
Less: Net income (loss) attributable to noncontrolling interests	**32**	12	(1)
Less: Net income attributable to redeemable noncontrolling interests	**4**	2	4
Net income attributable to the Company	**$ 338**	$ 215	$ 172

NOTES (continued)
Southern Power Company and Subsidiary Companies 2016 Annual Report

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2016 and 2015 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income Attributable to the Company
		(in millions)	
March 2016	**$ 315**	**$ 47**	**$ 50**
June 2016	**373**	**81**	**89**
September 2016	**500**	**134**	**176**
December 2016	**389**	**28**	**23**
March 2015	$ 348	$ 67	$ 33
June 2015	337	75	46
September 2015	401	129	102
December 2015	304	55	34

The Company's business is influenced by seasonal weather conditions.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2012 - 2016
Southern Power Company and Subsidiary Companies 2016 Annual Report

	2016	2015	2014	2013	2012
Operating Revenues (in millions):					
Wholesale — non-affiliates	$ 1,146	$ 964	$ 1,116	$ 923	$ 754
Wholesale — affiliates	419	417	383	346	425
Total revenues from sales of electricity	1,565	1,381	1,499	1,269	1,179
Other revenues	12	9	2	6	7
Total	$ 1,577	$ 1,390	$ 1,501	$ 1,275	$ 1,186
Net Income Attributable to Southern Power (in millions)	$ 338	$ 215	$ 172	$ 166	$ 175
Cash Dividends on Common Stock (in millions)	$ 272	$ 131	$ 131	$ 129	$ 127
Return on Average Common Equity (percent)	9.79	10.16	10.39	10.73	11.72
Total Assets (in millions) [(a)(b)]	$ 15,169	$ 8,905	$ 5,233	$ 4,417	$ 3,771
Property, Plant, and Equipment — In Service (in millions)	$ 12,728	$ 7,275	$ 5,657	$ 4,696	$ 4,060
Capitalization (in millions):					
Common stock equity	$ 4,430	$ 2,483	$ 1,752	$ 1,564	$ 1,522
Redeemable noncontrolling interests	164	43	39	29	8
Noncontrolling interests	1,245	781	219	—	—
Long-term debt [(a)]	5,068	2,719	1,085	1,607	1,297
Total (excluding amounts due within one year)	$ 10,907	$ 6,026	$ 3,095	$ 3,200	$ 2,827
Capitalization Ratios (percent):					
Common stock equity	40.6	41.2	56.6	48.9	53.8
Redeemable noncontrolling interests	1.5	0.7	1.3	0.9	0.3
Noncontrolling interests	11.4	13.0	7.1	—	—
Long-term debt [(a)]	46.5	45.1	35.0	50.2	45.9
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Kilowatt-Hour Sales (in millions):					
Wholesale — non-affiliates	23,213	18,544	19,014	15,111	15,637
Wholesale — affiliates	15,950	16,567	11,194	9,359	16,373
Total	39,163	35,111	30,208	24,470	32,010
Plant Nameplate Capacity Ratings (year-end) (megawatts) [(c)]	12,442	9,808	9,185	8,924	8,764
Maximum Peak-Hour Demand (megawatts):					
Winter	3,469	3,923	3,999	2,685	3,018
Summer	4,303	4,249	3,998	3,271	3,641
Annual Load Factor (percent)	50.0	49.0	51.8	54.2	48.6
Plant Availability (percent)	91.6	93.1	91.8	91.8	92.9
Source of Energy Supply (percent):					
Natural gas	79.4	89.5	86.0	88.5	91.0
Solar, Wind, and Biomass	12.1	4.3	2.9	1.1	0.5
Purchased power —					
From non-affiliates	6.8	4.7	6.4	6.4	7.2
From affiliates	1.7	1.5	4.7	4.0	1.3
Total	100.0	100.0	100.0	100.0	100.0

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $11 million, $12 million, and $9 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(b) A reclassification of deferred tax assets from Total Assets of $306 million, $- million, and $- million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(c) Plant nameplate capacity ratings include 100% of all solar facilities. When taking into consideration the Company's 90% equity interest in STR and SRP's various equity interests in its subsidiaries, the Company's equity portion of total nameplate capacity for 2016 is 11,768 MW.

SOUTHERN COMPANY GAS

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Southern Company Gas and Subsidiary Companies 2016 Annual Report

The management of Southern Company Gas (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2016 .

/s/ Andrew W. Evans
Andrew W. Evans
Chairman, President, and Chief Executive Officer

/s/ Elizabeth W. Reese
Elizabeth W. Reese
Executive Vice President, Chief Financial Officer, and Treasurer

February 21, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Southern Company Gas

We have audited the accompanying consolidated balance sheet of Southern Company Gas and Subsidiary Companies (formerly known as AGL Resources Inc.) (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2016 (Successor), and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for the six month periods ended June 30, 2016 (Predecessor) and December 31, 2016 (Successor). These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. We did not audit the financial statements of Southern Natural Gas Company, L.L.C. (SNG), the Company's investment in which is accounted for by the use of the equity method. The accompanying consolidated financial statements of the Company include its equity investment in SNG of $1,394 million as of December 31, 2016 , and its earnings from its equity method investment in SNG of $56 million for the six month period ended December 31, 2016 . Those statements were audited by other auditors whose report (which expresses an unqualified opinion on SNG's financial statements and contains an emphasis of matter paragraph concerning the extent of its operations and relationships with affiliated entities) has been furnished to us, and our opinion, insofar as it relates to the amounts included for SNG, is based solely on the report of the other auditors.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit and the report of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audit and the report of the other auditors, such consolidated financial statements (pages II-586 to II-643) present fairly, in all material respects, the financial position of Southern Company Gas and Subsidiary Companies as of December 31, 2016 , and the results of their operations and their cash flows for the six-month periods ended June 30, 2016 (Predecessor) and December 31, 2016 (Successor), in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 21, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Southern Company Gas

In our opinion, the consolidated balance sheet as of December 31, 2015 and the related consolidated statements of income, comprehensive income, common stockholders' equity, and cash flows for each of the two years in the period ended December 31, 2015 present fairly, in all material respects, the financial position of Southern Company Gas (formerly AGL Resources Inc.) and its subsidiaries as of December 31, 2015 , and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2015 , in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule for each of the two years in the period ended December 31, 2015 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits. We conducted our audits of these financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Atlanta, Georgia
February 11, 2016

DEFINITIONS

Term	Meaning
AFUDC	Allowance for funds used during construction
ASC	Accounting Standards Codification
Atlanta Gas Light	Atlanta Gas Light Company
Atlantic Coast Pipeline	Atlantic Coast Pipeline, LLC
Chattanooga Gas	Chattanooga Gas Company
Chicago Hub	A venture of Nicor Gas, which provides natural gas storage and transmission-related services to marketers and gas distribution companies
CUB	Citizens Utility Board, in Illinois
Dalton Pipeline	A 50% undivided ownership interest in a pipeline facility in Georgia
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings, Inc.
Florida PSC	Florida Public Service Commission, the state regulatory agency for Florida City Gas
GAAP	U.S. generally accepted accounting principles
Georgia PSC	Georgia Public Service Commission, the state regulatory agency for Atlanta Gas Light
Heating Degree Days	A measure of weather, calculated when the average daily temperatures are less than 65 degrees Fahrenheit
Heating Season	The period from November through March when natural gas usage and operating revenues are generally higher
Horizon Pipeline	Horizon Pipeline Company, LLC
Illinois Commission	Illinois Commerce Commission, the state regulatory agency for Nicor Gas
IRS	Internal Revenue Service
ITC	Investment tax credit
LIFO	Last-in, first-out
LNG	Liquefied natural gas
LOCOM	Lower of weighted average cost or current market price
Marketers	Marketers selling retail natural gas in Georgia and certificated by the Georgia PSC
Merger	The merger of AMS Corp., a wholly-owned, direct subsidiary of Southern Company, with and into Southern Company Gas, effective July 1, 2016, with Southern Company Gas continuing as the surviving corporation and a wholly-owned, direct subsidiary of Southern Company
MGP	Manufactured gas plant
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
natural gas distribution utilities	Southern Company Gas' seven natural gas distribution utilities (Nicor Gas, Atlanta Gas Light, Virginia Natural Gas, Elizabethtown Gas, Florida City Gas, Chattanooga Gas, and Elkton Gas)
New Jersey BPU	New Jersey Board of Public Utilities, the state regulatory agency for Elizabethtown Gas
Nicor	Nicor Inc. - former holding company of Nicor Gas
Nicor Gas	Northern Illinois Gas Company, doing business as Nicor Gas Company
Nicor Gas Credit Facility	$700 million credit facility entered into by Nicor Gas to support its commercial paper program
NYMEX	New York Mercantile Exchange, Inc.
OCI	Other comprehensive income

DEFINITIONS
(continued)

Term	Meaning
Pad gas	Volumes of non-working natural gas used to maintain the operational integrity of the natural gas storage facility
PennEast Pipeline	PennEast Pipeline Company, LLC
Piedmont	Piedmont Natural Gas Company, Inc.
Pivotal Utility Holdings	Pivotal Utility Holdings, Inc., doing business as Elizabethtown Gas, Elkton Gas, and Florida City Gas
PRP	Pipeline Replacement Program, Atlanta Gas Light's 15-year infrastructure replacement program, which ended in December 2013
PSC	Public Service Commission
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
Sequent	Sequent Energy Management, L.P.
SNG	Southern Natural Gas Company, L.L.C.
Southern Company	The Southern Company
Southern Company Gas Capital	Southern Company Gas Capital Corporation (formerly known as AGL Capital Corporation), a 100%-owned subsidiary of Southern Company Gas
Southern Company Gas Credit Facility	$1.3 billion credit agreement entered into by Southern Company Gas Capital to support its commercial paper program
Southern Company system	Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), Southern Electric Generating Company, Southern Nuclear, SCS, Southern LINC, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries
Southern LINC	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
SouthStar	SouthStar Energy Services, LLC
STRIDE	Atlanta Gas Light's Strategic Infrastructure Development and Enhancement program
traditional electric operating companies	Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company
Triton	Triton Container Investments, LLC
Tropical Shipping	Tropical Shipping and Construction Company Limited, which was sold in 2014
VIE	Variable interest entity
Virginia Commission	Virginia State Corporation Commission, the state regulatory agency for Virginia Natural Gas
Virginia Natural Gas	Virginia Natural Gas, Inc.
WACOG	Weighted average cost of gas

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Southern Company Gas and Subsidiary Companies 2016 Annual Report

OVERVIEW

Business Activities

Southern Company Gas (formerly known as AGL Resources Inc.) is an energy services holding company whose primary business is the distribution of natural gas in seven states – Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee, and Maryland – through seven utilities. Southern Company Gas and its subsidiaries (the Company) are also involved in several other complementary businesses.

In conjunction with the Merger, the Company changed the names of its reportable segments to better align with its new parent company. The Company has four reportable segments – gas distribution operations (formerly referred to as distribution operations), gas marketing services (formerly referred to as retail operations), wholesale gas services (formerly referred to as wholesale services), and gas midstream operations (formerly referred to as midstream operations) – and one non-reportable segment, all other. See Note 12 to the financial statements for additional information.

Many factors affect the opportunities, challenges, and risks of the Company's business. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow natural gas sales, and to effectively manage and secure timely recovery of costs. 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.

Merger with Southern Company

On July 1, 2016, the Company completed the Merger, which was accounted for by Southern Company using the acquisition method of accounting whereby the assets acquired and liabilities assumed were recognized at fair value as of the acquisition date. Pushdown accounting was applied to the Company, which created a new cost basis assigned to assets, liabilities, and equity as of the acquisition date. Accordingly, the successor period financial statements reflect a new basis of accounting, and successor and predecessor period financial results (separated by a heavy black line) are presented, but are not comparable. As a result of the application of acquisition accounting, certain discussions herein include disclosure of the predecessor and successor periods.

The Company's results for the successor period of July 1, 2016 through December 31, 2016 include a $20 million pre-tax decrease in earnings that is comprised of reduced revenues and increased amortization expense, partially offset by lower interest expense, all as a result of the fair value adjustments to certain assets and liabilities in the application of acquisition accounting.

For the successor period of July 1, 2016 through December 31, 2016, Merger-related expenses were $41 million . Merger-related expenses were $56 million and $44 million for the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, respectively. See RESULTS OF OPERATIONS herein for information related to Merger-related expenses. Also, see Note 11 to the financial statements under "Merger with Southern Company" for additional information relating to the Merger.

Investment in SNG

On September 1, 2016, the Company paid approximately $1.4 billion to acquire a 50% equity interest in SNG, which is the owner of a 7,000 -mile pipeline system connecting natural gas supply basins in Texas, Louisiana, Mississippi, and Alabama to markets in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina, and Tennessee. The investment in SNG is accounted for using the equity method. The Company recorded equity investment income of $56 million from this investment through December 31, 2016. See Note 4 to the financial statements under "Equity Method Investments – SNG" and Note 11 to the financial statements under "Investment in SNG" for additional information.

Other Matters

On October 3, 2016, the Company completed its purchase of Piedmont's 15% interest in SouthStar for $160 million . See Note 4 to the financial statements under "Variable Interest Entities" for additional information.

Operating Metrics

The Company continues to focus on several operating metrics, including Heating Degree Days, customer count, and volumes of natural gas sold.

Heating Degree Days

The Company measures weather and the effect on its business using Heating Degree Days. Generally, increased Heating Degree Days result in higher demand for natural gas on the Company's distribution system. With the exception of its utilities in Illinois and Florida, the Company has various regulatory mechanisms, such as weather normalization mechanisms, which limit its exposure to weather changes within typical ranges in each of its utilities' respective service territories. However, the utility customers in Illinois and the gas marketing services customers primarily in Georgia can be impacted by warmer- or colder-than-normal weather. The Company utilizes weather hedges at gas distribution operations and gas marketing services to reduce negative earnings impacts in the event of warmer-than-normal weather, while retaining all of the earnings upside in the event of colder-than-normal weather for gas distribution operations in Illinois and most of the earnings upside for gas marketing services.

The following table presents the Heating Degree Days information for Illinois and Georgia.

	Years Ended December 31,				**2016 vs. 2015**	2015 vs. 2014	**2016 vs. normal**
	Normal [(a)]	**2016**	2015	2014	**(warmer)**	(warmer)	**(warmer)**
		(in thousands)					
Illinois [(b)]	**5,869**	**5,243**	5,433	6,556	**(3)%**	(17)%	**(11)%**
Georgia	**2,618**	**2,175**	2,204	2,882	**(1)%**	(24)%	**(17)%**

(a) Normal represents the 10-year average from January 1, 2006 through December 31, 2015 for Illinois at Chicago Midway International Airport and for Georgia at Atlanta Hartsfield-Jackson International Airport, based on information obtained from the National Oceanic and Atmospheric Administration, National Climatic Data Center.

(b) The 10-year average Heating Degree Days established by the Illinois Commission in Nicor Gas' last rate case is 5,600 for the 12 months from 1999 through 2008.

In 2016 , weather in Illinois was 11% warmer than normal and 3% warmer than in 2015 . The Company hedged its exposure to warmer-than-normal weather at Nicor Gas; therefore, the negative pre-tax weather impact on gas distribution operations was limited to $1 million for the successor period of July 1, 2016 through December 31, 2016 and $7 million for the predecessor period of January 1, 2016 through June 30, 2016. Overall, weather in Illinois was warmer than normal during 2015; however, weather in the first quarter 2015 was 10% colder than normal and in the fourth quarter 2015 was 28% warmer than normal. Since the Company hedged its exposure to warmer-than-normal weather, the positive pre-tax weather impact in 2015 on gas distribution operations was $2 million.

In 2016, weather in Georgia was 17% warmer than normal and 1% warmer than 2015. The Company hedged its exposure to warmer-than-normal weather for the first and fourth quarters of 2016 separately. As such, the negative pre-tax weather impact was limited to $4 million for the successor period of July 1, 2016 through December 31, 2016 and there was no weather impact for the predecessor period of January 1, 2016 through June 30, 2016 at gas marketing services.

Customer Count

The number of customers at gas distribution operations and energy customers at gas marketing services can be impacted by natural gas prices, economic conditions, and competition from alternative fuels. The Company's gas marketing services' energy customers are primarily located in Georgia and Illinois. The customer metrics presented in the following table highlight the number of customers to which the Company provided services at the date or for the period indicated.

	December 31,		
	2016 [(a)]	2015 [(b)]	2014 [(b)]
		(in thousands)	
Gas distribution operations	**4,586**	4,526	4,497
Gas marketing services			
Energy customers	**656**	645	628
Market share of energy customers in Georgia	**29.6%**	29.7%	30.6%
Service contracts	**1,198**	1,171	1,182

(a) Includes customer and contract counts at December 31, 2016.
(b) Includes average customer and contract counts for the years ended December 31, 2015 and 2014.

The Company anticipates overall customer growth trends at gas distribution operations to continue in 2017 , as it expects continued improvement in the new housing market and low natural gas prices. The Company uses a variety of targeted marketing programs to attract new customers and to retain existing customers. These efforts include adding residential customers,

multifamily complexes, and commercial and industrial customers who use natural gas for purposes other than heating, as well as evaluating and launching new natural gas related programs, products, and services to enhance customer growth, mitigate customer attrition, and increase operating revenues. These programs generally emphasize natural gas as the fuel of choice for customers and seek to expand the use of natural gas through a variety of promotional activities. The Company also targets customer conversions to natural gas from other energy sources, emphasizing the pricing advantage of natural gas. These programs focus on premises that could be connected to the Company's distribution system at little or no cost to the customer. In cases where conversion cost can be a disincentive, the Company may employ rebate programs and other assistance to address customer cost issues.

In 2017 , gas marketing services intends to continue efforts to enter into targeted markets and expand energy customers and service contracts.

Volumes of Natural Gas Sold

The Company's natural gas volume metrics for gas distribution operations and gas marketing services, as shown in the following table, illustrate the effects of weather and customer demand for natural gas compared to the two prior years. Wholesale gas services' physical sales volumes represent the daily average natural gas volumes sold to its customers.

	Year Ended December 31,			2016 vs. 2015	2015 vs. 2014
	2016	2015	2014	**% Change**	% Change
Gas distribution operations *(mmBtu in millions)*					
Firm	**670**	695	766	**(3.6)%**	(9.3)%
Interruptible	**96**	99	106	**(3.0)%**	(6.6)%
Total	**766**	794	872	**(3.5)%**	(8.9)%
Gas marketing services *(mmBtu in millions)*					
Firm:					
Georgia	**34**	35	41	**(2.9)%**	(14.6)%
Illinois	**12**	13	17	**(7.7)%**	(23.5)%
Other emerging markets	**12**	11	10	**9.1 %**	10.0 %
Interruptible:					
Large commercial and industrial	**14**	14	17	**— %**	(17.6)%
Total	**72**	73	85	**(1.4)%**	(14.1)%
Wholesale gas services					
Daily physical sales *(mmBtu in millions/day)*	**7.4**	6.8	6.3	**8.8 %**	7.9 %

Seasonality of Results

During the Heating Season, natural gas usage and operating revenues are generally higher as more customers are connected to the Company's distribution systems and natural gas usage is higher in periods of colder weather. Occasionally in the summer, wholesale gas services' operating revenues are impacted due to peak usage by power generators in response to summer energy demands. Seasonality also affects the comparison of certain balance sheet items across quarters, including receivables, unbilled revenues, natural gas for sale, and notes payable. However, these items are comparable when reviewing the Company's annual results. The Company's base operating expenses, excluding cost of natural gas, bad debt expense, and certain incentive compensation costs, are incurred relatively equally over any given year. Thus, the Company's operating results can vary significantly from quarter to quarter as a result of seasonality, which is illustrated in the table below.

	Percent Generated During Heating Season		
	Operating Revenues	**EBIT**	**Net Income**
Successor - July 1, 2016 through December 31, 2016	**67.1%**	**81.5%**	**96.5%**
Predecessor - January 1, 2016 through June 30, 2016	**70.0%**	**107.0%**	**138.9%**
2015	68.1%	77.3%	85.0%
2014	72.6%	79.8%	89.6%

Earnings

Net income attributable to Southern Company Gas for the successor period of July 1, 2016 through December 31, 2016 was $114 million . While the core operations of the business have not changed significantly since the completion of the Merger, earnings for the successor period included $26 million from the Company's investment in SNG, which was completed on September 1, 2016, offset by $12 million due to the impact of the pushdown of acquisition accounting and $27 million of Merger-related expenses. Net income for the successor period reflected higher revenues from continued investment in infrastructure programs and increased usage and customer growth, partially offset by warmer weather, net of hedging, and lower earnings from wholesale gas services due to mark-to-market losses. See RESULTS OF OPERATIONS herein for information on the Company's financial performance.

Net income attributable to Southern Company Gas for the predecessor period of January 1, 2016 through June 30, 2016 was $131 million , which included $41 million of Merger-related expenses. Net income for the predecessor period reflected higher revenues from continued investment in infrastructure programs, partially offset by warm weather, net of hedging, and low earnings from wholesale gas services due to mark-to-market losses.

Net income attributable to Southern Company Gas for the predecessor year ended December 31, 2015 was $353 million , a decrease of $129 million from 2014 primarily due to lower earnings from wholesale gas services. Net income in 2015 also included $26 million of Merger-related expenses and a $9 million non-cash goodwill impairment charge. The Company also recorded an $80 million loss from discontinued operations in 2014. In 2014, wholesale gas services experienced significantly higher commercial activity, primarily in the first quarter, and reported substantial mark-to-market gains, net of LOCOM adjustments, from price volatility generated by colder-than-normal weather, which increased its revenue.

RESULTS OF OPERATIONS

Operating Results

Results for the successor period of July 1, 2016 through December 31, 2016 and the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 reflect certain Merger-related expenses, which are not expected to have a continuing impact on the results of operations going forward, and those amounts are discussed in the results of operations below. A condensed income statement for the Company follows:

	Successor	Predecessor		
	July 1, 2016 through December 31,	January 1, 2016 through June 30,	Years Ended December 31,	
	2016	2016	2015	2014
	(in millions)	(in millions)		
Operating revenues	$ 1,652	$ 1,905	$ 3,941	$ 5,385
Cost of natural gas	613	755	1,617	2,729
Cost of other sales	10	14	28	36
Other operations and maintenance	482	454	928	939
Depreciation and amortization	238	206	397	380
Taxes other than income taxes	71	99	181	208
Merger-related expenses	41	56	44	—
Total operating expenses	1,455	1,584	3,195	4,292
Gain on disposition of assets	—	—	—	2
Operating income	197	321	746	1,095
Interest expense, net of amounts capitalized	81	96	175	182
Earnings from equity method investments	60	2	6	8
Other income (expense), net	14	5	9	9
Earnings before income taxes	190	232	586	930
Income taxes	76	87	213	350
Income from continuing operations	114	145	373	580
Loss from discontinued operations, net of tax	—	—	—	80
Net Income	114	145	373	500
Less: Net income attributable to noncontrolling interest	—	14	20	18
Net Income Attributable to Southern Company Gas	$ 114	$ 131	$ 353	$ 482

Operating Revenues

Operating revenues for the successor period of July 1, 2016 through December 31, 2016 were $1.7 billion . For the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014, operating revenues were $1.9 billion , $3.9 billion , and $5.4 billion , respectively.

Natural gas revenues for the successor period of July 1, 2016 through December 31, 2016 reflect continued infrastructure replacement program investment at gas distribution operations, partially offset by the warm weather, net of hedging, and low revenues from wholesale gas services due to low commercial activity and mark-to-market losses. Natural gas revenues for the successor period reflect fair value adjustments to certain assets and liabilities in the application of acquisition accounting of $8 million and $10 million for gas marketing services and wholesale gas services, respectively.

Natural gas revenues for the predecessor period of January 1, 2016 through June 30, 2016 reflect similar key trends at gas distribution operations as discussed above for the successor period. Natural gas revenues for the predecessor period also reflect mark-to-market losses as a result of changes in natural gas prices, low commercial activity driven by changes in price volatility, and a decrease in the value of transportation and forward commodity derivatives from price movements related to natural gas transportation positions at wholesale gas services.

Natural gas revenues for the predecessor year ended December 31, 2015 represented a decrease of $1.4 billion from 2014 due to lower natural gas prices, lower volumes of natural gas sold to customers due to warmer weather in 2015 compared to extremely cold weather in 2014, and decreased commercial activity at wholesale gas services that experienced unusually high commercial activity in 2014 largely driven by colder weather and high price volatility, which presented opportunities for the transportation and storage portfolio in the Northeast and Midwest.

Cost of Natural Gas

Natural gas costs are the largest expense for the Company. Excluding Atlanta Gas Light, which does not sell natural gas to end-use customers, gas distribution operations charges its utility customers for natural gas consumed using natural gas cost recovery mechanisms set by the applicable state regulatory agencies. Under these mechanisms, all prudently incurred natural gas costs are passed through to customers without markup, subject to regulatory review. Gas distribution operations defers or accrues the difference between the actual cost of natural gas and the amount of commodity revenue earned in a given period, such that no adjusted operating margin is recognized related to these costs. The deferred or accrued amount is either billed or refunded to customers prospectively through adjustments to the commodity rate. Deferred natural gas costs are reflected as regulatory assets and accrued natural gas costs are reflected as regulatory liabilities.

Gas marketing services customers are charged for actual or estimated natural gas consumed. Cost of natural gas includes the cost of fuel and lost and unaccounted for gas, adjustments to reduce the value of inventories to market value, and gains and losses associated with certain derivatives.

Cost of natural gas was $613 million for the successor period of July 1, 2016 through December 31, 2016 , which reflected low demand for natural gas driven by warm weather in the fourth quarter 2016.

Cost of natural gas was $755 million for the predecessor period of January 1, 2016 through June 30, 2016 , which reflected low demand for natural gas driven by warm weather in the first quarter 2016.

For the predecessor years ended December 31, 2015 and 2014, cost of natural gas was $1.6 billion and $2.7 billion , respectively. The decrease in 2015 of $1.1 billion , or 40.7% , was primarily due to lower demand for natural gas driven by warmer weather in 2015 compared to 2014 as weather in 2014 was extremely cold.

Other Operations and Maintenance Expenses

For the successor period of July 1, 2016 through December 31, 2016 , other operations and maintenance expenses were $482 million , which includes labor, outside services related to pipeline compliance and maintenance, and legal services and other professional fees, as well as benefit costs.

For the predecessor period of January 1, 2016 through June 30, 2016 , other operations and maintenance expenses were $454 million , consistent with the level of expenses in the corresponding period in 2015.

For the predecessor year ended December 31, 2015 , other operations and maintenance expenses were $928 million , a decrease of $11 million compared to 2014. The decrease was primarily due to decreased benefit expense and incentive compensation in 2015 driven by lower earnings, which was partially offset by a $14 million goodwill impairment charge in 2015 . See Note 1 to the financial statements for additional information regarding goodwill impairment.

See Note 2 to the financial statements for additional information regarding benefit plans.

Depreciation and Amortization

For the successor period of July 1, 2016 through December 31, 2016, depreciation and amortization was $238 million , including $23 million of additional amortization of intangible assets as a result of fair value adjustments in acquisition accounting, as well as depreciation at gas distribution operations due to continued investment in infrastructure programs and other rate base items.

For the predecessor period of January 1, 2016 through June 30, 2016 , depreciation and amortization was $206 million , reflecting depreciation related to additional assets placed in service at gas distribution operations.

For the predecessor year ended December 31, 2015 , depreciation and amortization was $397 million , an increase of $17 million , or 4.5% , compared to 2014, primarily due to increased depreciation related to additional assets placed in service at gas distribution operations.

Taxes Other Than Income Taxes

For the successor period of July 1, 2016 through December 31, 2016 , taxes other than income taxes were $71 million , which consisted primarily of revenue tax expenses, property taxes, and payroll taxes.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014, taxes other than income taxes were $99 million , $181 million , and $208 million , respectively, which consisted primarily of revenue tax expenses, property taxes, and payroll taxes. The decrease in 2015 was partially due to a favorable property tax settlement in 2015.

Merger-Related Expenses

For the successor period of July 1, 2016 through December 31, 2016 , Merger-related expenses were $41 million , including $18 million in rate credits provided to the customers of Elizabethtown Gas and Elkton Gas as conditions of the Merger, $20 million for additional compensation-related expenses, and $3 million for financial advisory fees, legal expenses, and other Merger-related costs.

For the predecessor period of January 1, 2016 through June 30, 2016 , Merger-related expenses were $56 million , including $31 million for financial advisory fees, legal expenses, and other Merger-related costs and $25 million for additional compensation-related expenses.

For the predecessor year ended December 31, 2015, Merger-related expenses were $44 million , including $20 million for financial advisory fees, legal expenses, and other Merger-related costs and $24 million for additional compensation-related expenses due to remeasurement of performance share units based upon the increase in the Company's stock price since the announcement of the Merger.

See Note 11 to the financial statements under "Merger with Southern Company" for additional information.

Interest Expense, Net of Amounts Capitalized

For the successor period of July 1, 2016 through December 31, 2016 , interest expense, net of amounts capitalized, was $81 million , reflecting the $19 million fair value adjustment on long-term debt in acquisition accounting, as well as interest expense incurred as a result of new debt issuances. See Note 6 to the financial statements for additional information.

For the predecessor period of January 1, 2016 through June 30, 2016 , interest expense, net of amounts capitalized, was $96 million , reflecting debt issuances and redemptions during the period, and interest expensed for regulatory infrastructure programs as the Company expensed previously deferred interest with the corresponding recovery in revenue.

For the predecessor year ended December 31, 2015 , interest expense, net of amounts capitalized, was $175 million , a decrease of $7 million , or 3.8% , compared to the same period in 2014. The decrease was due to an increase in deferred interest of $7 million related to regulatory infrastructure program expenses.

See FUTURE EARNINGS POTENTIAL – "Financing Activities" herein for additional information.

Earnings from Equity Method Investments

For the successor period of July 1, 2016 through December 31, 2016 , earnings from equity method investments were $60 million , primarily reflecting earnings from the Company's September 2016 investment in SNG.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014, earnings from equity method investments were not material.

Other Income (Expense), Net

For the successor period of July 1, 2016 through December 31, 2016 , other income (expense), net was $14 million related primarily to the tax gross-up of contributions received from customers and spending under regulatory infrastructure programs.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014, other income (expense), net was $5 million, $9 million, and $9 million, respectively.

Income Taxes

For the successor period of July 1, 2016 through December 31, 2016 , income taxes were $76 million . The effective tax rate in this period reflects certain nondeductible Merger-related charges.

For the predecessor period of January 1, 2016 through June 30, 2016 , income taxes were $87 million . The effective tax rate in this period reflects certain nondeductible Merger-related expenses and other charges.

For the predecessor year ended December 31, 2015 , income taxes were $213 million , a decrease of $137 million , or 39.1% , compared to 2014, primarily due to higher pre-tax earnings in 2014 resulting from extremely cold weather.

Noncontrolling Interest

Prior to the October 3, 2016 acquisition of Piedmont's 15% interest in SouthStar, net income attributable to noncontrolling interest was recorded on the consolidated statements of income. Since the Company now owns 100% of SouthStar's equity interests, it will not record net income attributable to noncontrolling interest related to SouthStar in future periods. See Note 4 to the financial statements under "Variable Interest Entities" 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.

Performance and Non-GAAP Measures

Prior to the Merger, the Company evaluated segment performance using earnings before interest and taxes (EBIT), which includes operating income and other income (expenses) and excludes interest expense, net of amounts capitalized, and income taxes, which the Company evaluated on a consolidated basis for those periods. EBIT is used herein to discuss the results of the Company's segments for all predecessor periods, as EBIT was the primary measure of segment profit or loss for those periods. Subsequent to the Merger, the Company changed its segment performance measure from EBIT to net income to better align with the performance measure utilized by its new parent company. EBIT for the successor period of July 1, 2016 through December 31, 2016 presented herein is considered a non-GAAP measure. The Company also discusses consolidated EBIT, which is considered a non-GAAP measure for all periods presented herein. The presentation of consolidated EBIT is believed to provide useful supplemental information regarding a consolidated measure of profit or loss. The Company further believes the presentation of segment EBIT for the successor period of July 1, 2016 through December 31, 2016 is useful as it allows for a measure of comparability to other companies with different capital and legal structures, which accordingly may be subject to different interest rates and effective tax rates. The applicable reconciliations of net income to consolidated EBIT and segment EBIT, respectively, are provided herein.

Adjusted operating margin is a non-GAAP measure that is calculated as operating revenues minus cost of natural gas, cost of other sales, and revenue tax expense. Adjusted operating margin excludes other operations and maintenance expenses, depreciation and amortization, taxes other than income taxes, and Merger-related expenses, which are included in the calculation of operating income as calculated in accordance with GAAP and reflected in the consolidated statements of income. The presentation of adjusted operating margin is believed to provide useful information regarding the contribution resulting from customer growth at gas distribution operations since the cost of natural gas and revenue tax expense can vary significantly and are generally billed directly to customers. The Company further believes that utilizing adjusted operating margin at gas marketing services, wholesale gas services, and gas midstream operations allows it to focus on a direct measure of adjusted operating margin before overhead costs. The applicable reconciliation of operating income to adjusted operating margin is provided herein.

EBIT and adjusted operating margin should not be considered alternatives to, or more meaningful indicators of, the Company's operating performance than consolidated net income attributable to the Company or operating income as determined in accordance with GAAP. In addition, the Company's adjusted operating margin may not be comparable to similarly titled measures of other companies.

See RESULTS OF OPERATIONS herein for information on the Company's financial performance.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Reconciliations of consolidated operating income to adjusted operating margin and consolidated net income attributable to the Company to EBIT are as follows:

	Successor	Predecessor		
	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016	Years Ended December 31, 2015	Years Ended December 31, 2014
	(in millions)	*(in millions)*		
Operating Income	$ 197	$ 321	$ 746	$ 1,095
Other operating expenses [(a)]	832	815	1,550	1,527
Gain on disposition of assets	—	—	—	(2)
Revenue tax expense [(b)]	(31)	(56)	(101)	(130)
Adjusted Operating Margin	$ 998	$ 1,080	$ 2,195	$ 2,490

(a) Adjusted for the following operating expenses: other operations and maintenance, depreciation and amortization, taxes other than income taxes, and Merger-related expenses.
(b) Adjusted for Nicor Gas' revenue tax expenses, which are passed through directly to customers.

	Successor	Predecessor		
	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016	Years Ended December 31, 2015	Years Ended December 31, 2014
	(in millions)	*(in millions)*		
Consolidated Net Income Attributable to Southern Company Gas	$ 114	$ 131	$ 353	$ 562
Net income attributable to noncontrolling interest	—	14	20	18
Income taxes	76	87	213	350
Interest expense, net of amounts capitalized	81	96	175	182
EBIT	$ 271	$ 328	$ 761	$ 1,112

Segment Information

Adjusted operating margin, operating expenses, and the Company's primary performance metric for each segment are illustrated in the tables below.

	Successor			Predecessor		
	July 1, 2016 through December 31, 2016			January 1, 2016 through June 30, 2016		
	Adjusted Operating Margin [(*)]	Operating Expenses [(*)]	Net Income	Adjusted Operating Margin [(*)]	Operating Expenses [(*)]	EBIT
	(in millions)			*(in millions)*		
Gas distribution operations	$ 817	$ 595	$ 77	$ 911	$ 560	$ 353
Gas marketing services	139	112	19	190	81	109
Wholesale gas services	24	26	—	(36)	33	(68)
Gas midstream operations	19	26	20	15	24	(6)
All other	3	46	(2)	4	65	(60)
Intercompany eliminations	(4)	(4)	—	(4)	(4)	—
Consolidated	$ 998	$ 801	$ 114	$ 1,080	$ 759	$ 328

(*) Adjusted operating margin and operating expenses are adjusted for Nicor Gas revenue tax expenses, which are passed through directly to customers.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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	Predecessor					
	Year Ended December 31, 2015			Year Ended December 31, 2014		
	Adjusted Operating Margin (*)	Operating Expenses (*)	EBIT	Adjusted Operating Margin (*)	Operating Expenses (*)	EBIT
	(in millions)			*(in millions)*		
Gas distribution operations	$ 1,657	$ 1,086	$ 581	$ 1,648	$ 1,075	$ 582
Gas marketing services	317	165	152	311	179	132
Wholesale gas services	183	71	110	501	79	425
Gas midstream operations	36	62	(23)	31	50	(17)
All other	7	70	(59)	7	22	(10)
Intercompany eliminations	(5)	(5)	—	(8)	(8)	—
Consolidated	$ 2,195	$ 1,449	$ 761	$ 2,490	$ 1,397	$ 1,112

(*) Adjusted operating margin and operating expenses are adjusted for Nicor Gas revenue tax expenses, which are passed through directly to customers.

Gas Distribution Operations

Gas distribution operations is the largest component of the Company's business and is subject to regulation and oversight by agencies in each of the states in which it serves. These agencies approve natural gas rates designed to provide the Company with the opportunity to generate revenues to recover the cost of natural gas delivered to its customers and its fixed and variable costs, including depreciation, interest, maintenance, and overhead costs, and to earn a reasonable return on its investments.

With the exception of Atlanta Gas Light, the Company's second largest utility that operates in a deregulated natural gas market and has a straight-fixed-variable rate design that minimizes the variability of its revenues based on consumption, the earnings of the regulated natural gas distribution utilities can be affected by customer consumption patterns that are a function of weather conditions, price levels for natural gas, and general economic conditions that may impact customers' ability to pay for natural gas consumed. The Company has various weather mechanisms, such as weather normalization mechanisms and weather derivative instruments, that limit its exposure to weather changes within typical ranges in its natural gas utilities' service territories.

Successor Period of July 1, 2016 through December 31, 2016

Net income of $77 million includes $817 million in adjusted operating margin, $595 million in operating expenses, and $11 million in other income (expense), net resulting in EBIT of $233 million . Net income also includes $105 million in interest expense and $51 million in income tax expense. Adjusted operating margin reflects revenue from continued investment in infrastructure replacement programs, partially offset by the impact of warm weather, net of hedging. Operating expenses reflect the depreciation associated with additional assets placed in service and the related expenses associated with pipeline compliance and maintenance activities.

Predecessor Period of January 1, 2016 through June 30, 2016

EBIT of $353 million includes $911 million in adjusted operating margin, $560 million in operating expense, and $2 million in other income (expense), net. Adjusted operating margin reflects increased revenue from continued investment in infrastructure replacement programs, increased customer usage and growth, partially offset by the impact of warm weather, net of hedging. Operating expenses reflect the depreciation associated with additional assets placed in service and the related expenses associated with pipeline compliance and maintenance activities.

Predecessor Years Ended December 31, 2015 and 2014

Gas distribution operations' year-over-year EBIT changes are presented in the following table:

	(in millions)
EBIT – 2014	**$ 582**
Adjusted operating margin	
Increase from pipeline infrastructure programs, primarily at Atlanta Gas Light and Nicor Gas	34
Increase mainly driven by customer usage and growth	13
Decrease related to weather, net of hedging	(20)
Decrease in rider program recoveries at Nicor Gas, offset in operating expenses below	(18)
Increase in adjusted operating margin	**9**
Operating expenses	
Decrease in rider program recoveries at Nicor Gas, offset in adjusted operating margin above	(18)
Increase in depreciation due to additional assets placed in service	19
Increase in benefit expenses primarily related to higher pension costs and medical benefits	12
Increase in 2015 due to write-off of PRP-related costs from global settlement	5
Increase in payroll and variable compensation costs	9
Decrease in bad debt expenses due to changes in natural gas consumption and prices	(2)
Decrease in weather-related expenses	(4)
Decrease in outside services and other expenses primarily due to maintenance programs	(5)
Decrease in fleet expenses resulting from lower fuel prices	(5)
Increase in operating expenses	**11**
Increase in other income	**1**
EBIT – 2015	**$ 581**

Gas Marketing Services

Gas marketing services consists of several businesses that provide energy-related products and services to natural gas markets. Gas marketing services is weather sensitive and uses a variety of hedging strategies, such as weather derivative instruments and other risk management tools, to partially mitigate potential weather impacts.

Successor Period of July 1, 2016 through December 31, 2016

Net income of $19 million includes $139 million in adjusted operating margin and $112 million in operating expenses, resulting in EBIT of $27 million . Net income also includes $1 million in interest expense and $7 million in income tax expense. Adjusted operating margin reflects a reduction of $5 million due to fair value adjustments to certain assets and liabilities in the application of acquisition accounting. Also reflected in adjusted operating margin are unrealized hedge gains and LOCOM adjustments. Operating expenses reflect a $2 million reduction in operations and maintenance expense and $23 million in additional amortization of intangible assets due to fair value adjustments to certain assets and liabilities in the application of acquisition accounting, as well as $6 million in litigation-related expense.

Predecessor Period of January 1, 2016 through June 30, 2016

EBIT of $109 million includes $190 million in adjusted operating margin and $81 million in operating expenses. Adjusted operating margin reflects revenue from gas marketing and warranty sales, which were partially offset by the impact of warm weather, net of hedging. Operating expenses reflect lower bad debt, marketing, and depreciation and amortization, compared to the same period in the prior year.

Predecessor Years Ended December 31, 2015 and 2014

Gas marketing services' year-over-year EBIT changes are presented in the following table:

		(in millions)
EBIT – 2014	**$**	**132**
Adjusted operating margin		
Increase in value of unrealized hedges as a result of changes in NYMEX natural gas prices, net of recoveries		19
Increase in warranty margins		2
LOCOM adjustments, net of recoveries		3
Decrease in gas marketing margins		(8)
Decrease due to weather, net of weather hedging		(9)
Other		(1)
Increase in adjusted operating margin		**6**
Operating expenses		
Decrease in depreciation and amortization		(3)
Decrease in outside services, labor and marketing expenses		(8)
Decrease in other expenses, primarily bad debt expenses		(3)
Decrease in operating expenses		**(14)**
EBIT – 2015	**$**	**152**

Wholesale Gas Services

Wholesale gas services is involved in asset management and optimization, storage, transportation, producer and peaking services, natural gas supply, natural gas services, and wholesale gas marketing. The Company has positioned the business to generate positive economic earnings even under low volatility market conditions that can result from a number of factors. When market price volatility increases, as in 2015, wholesale gas services is well positioned to capture significant value and generate stronger results. Wholesale gas services generated strong economic results for the successor period of July 1, 2016 through December 31, 2016, primarily due to capturing natural gas storage value resulting from widening forward storage seasonal spreads that will be realized upon the ultimate withdrawal from storage and sale of natural gas.

Successor Period of July 1, 2016 through December 31, 2016

Net income includes $24 million in adjusted operating margin, $26 million in operating expenses, and $2 million in other income (expense), net, resulting in no EBIT. Also included are $3 million in interest expense and $3 million in income tax benefit. Adjusted operating margin reflects a decrease of $10 million due to fair value adjustments to certain assets and liabilities in the application of acquisition accounting. Also reflected in adjusted operating margin are mark-to-market losses due to high natural gas prices in the fourth quarter 2016 and low revenue from commercial activity due to low volatility in natural gas prices and warm weather. Operating expenses reflect low incentive compensation expense due to low earnings.

Predecessor Period of January 1, 2016 through June 30, 2016

Loss before interest and taxes of $68 million includes $(36) million in adjusted operating margin, $33 million in operating expense, and $1 million in other income (expense), net. Adjusted operating margin reflects mark-to-market losses as a result of changes in natural gas prices, lower commercial activity driven by changes in price volatility, and a decrease due to mark-to-market losses on storage hedge derivatives of transportation and forward commodity derivatives from price movements related to natural gas transportation positions. Operating expenses reflect lower incentive compensation expense as compared to the same period in the prior year due to lower earnings.

Predecessor Years Ended December 31, 2015 and 2014

Wholesale gas services' year-over-year EBIT changes are presented in the following table:

	(in millions)
EBIT – 2014	$ 425
Adjusted operating margin	
Decrease in mark-to-market gains of storage derivatives as a result of changes in NYMEX natural gas prices	(41)
Decrease in commercial activity driven by changes in price volatility	(304)
Decrease in the value of transportation and forward commodity derivatives from price movements related to natural gas transportation positions	(27)
LOCOM adjustments, net of current period recoveries	54
Decrease in adjusted operating margin	(318)
Operating expenses	
Decrease in compensation and benefits driven largely by year-over-year changes in earnings and capture of natural gas storage value	(8)
Decrease in operating expenses	(8)
Decrease in other income primarily related to the gain on sale of Compass Energy in 2014	(5)
EBIT – 2015	$ 110

The following table illustrates the components of wholesale gas services' adjusted operating margin for the periods presented:

	Successor	Predecessor		
	July 1, 2016 through December 31,	**January 1, 2016 through June 30,**	Years Ended December 31,	
	2016	**2016**	2015	2014
	(in millions)	*(in millions)*		
Commercial activity recognized	**$ (10)**	**$ 34**	$ 140	$ 444
Gain (loss) on storage derivatives	**(20)**	**(38)**	45	86
Gain (loss) on transportation and forward commodity derivatives	**64**	**(31)**	11	38
LOCOM adjustments, net of current period recoveries	**—**	**(1)**	(13)	(67)
Purchase accounting adjustments to fair value inventory and contracts	**(10)**	**—**	—	—
Adjusted operating margin	**$ 24**	**$ (36)**	$ 183	$ 501

Change in Commercial Activity

The commercial activity at wholesale gas services includes recognition of storage and transportation values that were generated in prior periods, which reflect the impact of prior period hedge gains and losses as associated physical transactions occur. Increases in natural gas supply and warmer-than-normal weather during the 2015/2016 Heating Season and the resulting higher natural gas inventories at the end of 2015 caused natural gas prices to decline in the early part of 2016. However, as natural gas prices and forward storage or time spreads increased, largely in the first half of 2016, wholesale gas services was able to capture higher storage values to accommodate the increase in natural gas supply. While wholesale gas services experienced unusually high volatility in natural gas prices in early 2015 and low volatility in 2016 due partly to weather, in the near term, the Company anticipates continued low volatility in certain areas of wholesale gas services' portfolio.

Change in Storage and Transportation Derivatives

Volatility in the natural gas market arises from a number of factors, such as weather fluctuations or changes in supply or demand for natural gas in different regions of the U.S. The volatility of natural gas commodity prices has a significant impact on the Company's customer rates, long-term competitive position against other energy sources, and the ability of wholesale gas services to capture value from locational and seasonal spreads. In 2016, there was little price volatility; however, the potential for market

fundamentals indicating some level of increased volatility that would potentially benefit the Company's portfolio of pipeline transportation capacity exists. Additionally, increases in natural gas prices during 2016 and forward storage or time spreads applicable to the locations of wholesale gas services' specific storage positions resulted in storage derivative losses. Transportation and forward commodity derivative gains are primarily the result of narrowing transportation basis spreads due to continued supply constraints and increases in natural gas supply and warmer-than-normal weather, which impacted forward prices at natural gas receipt and delivery points, primarily in the Northeast and Midwest regions.

The natural gas that the Company purchases and injects into storage is accounted for at the LOCOM value utilizing gas daily or spot prices at the end of the year. Wholesale gas services recorded $1 million of LOCOM adjustments in the successor period of July 1, 2016 through December 31, 2016. Wholesale gas services recorded LOCOM adjustments excluding the impact of current period receivables of $3 million , $19 million , and $73 million for the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014, respectively.

Withdrawal Schedule and Physical Transportation Transactions

The expected natural gas withdrawals from storage and expected offset to prior hedge losses/gains associated with the transportation portfolio of wholesale gas services are presented in the following table, along with the net operating revenues expected at the time of withdrawal from storage and the physical flow of natural gas between contracted transportation receipt and delivery points. Wholesale gas services' expected net operating revenues exclude storage and transportation demand charges, as well as other variable fuel, withdrawal, receipt, and delivery charges, but are net of the estimated impact of profit sharing under its asset management agreements. Further, the amounts that are realizable in future periods are based on the inventory withdrawal schedule, planned physical flow of natural gas between the transportation receipt and delivery points, and forward natural gas prices at December 31, 2016. A portion of wholesale gas services' storage inventory and transportation capacity is economically hedged with futures contracts, which results in the realization of substantially fixed net operating revenues.

	Storage Withdrawal Schedule		
	Total storage (WACOG $2.76)	**Expected net operating gains** (a)	**Physical Transportation Transactions – Expected Net Operating Gains (Losses)** (b)
	(in mmBtu in millions)	*(in millions)*	*(in millions)*
2017	**67.2**	**$ 56**	**$ (38)**
2018 and thereafter	**2.9**	**3**	**6**
Total at December 31, 2016	**70.1**	**$ 59**	**$ (32)**

(a) Represents expected operating gains from planned storage withdrawals associated with existing inventory positions and could change as wholesale gas services adjusts its daily injection and withdrawal plans in response to changes in future market conditions and forward NYMEX price fluctuations. Also includes the impact of purchase accounting adjustments to reflect natural gas storage inventory at market value. Excluding the impact of these adjustments, the expected net operating gains at December 31, 2016 would have been $85 million.

(b) Represents the periods associated with the transportation derivative (gains) and losses during which the derivatives will be settled and the physical transportation transactions will occur that offset the derivative (gains) and losses that were previously recognized.

The unrealized storage and transportation derivative losses do not change the underlying economic value of wholesale gas services' storage and transportation positions and, based on current expectations, will primarily be reversed in 2017 when the related transactions occur and are recognized.

Gas Midstream Operations

Since the acquisition of the Company's 50% interest in SNG in September 2016, gas midstream operations consists primarily of gas pipeline investments, with storage and fuels also aggregated into this segment. Gas pipeline investments consist of the SNG interest, Horizon Pipeline, Atlantic Coast Pipeline, PennEast Pipeline, Dalton Pipeline, and Magnolia Pipeline.

Successor Period of July 1, 2016 through December 31, 2016

Net income of $20 million includes $19 million in adjusted operating margin, $26 million in operating expenses, and $59 million in other income, which results in EBIT of $52 million. Other income consists primarily of equity in earnings from the September 2016 investment in SNG. Also included in net income are $16 million in interest expense and $16 million in income tax expense.

Predecessor Periods of January 1, 2016 through June 30, 2016 and the Years Ended December 31, 2015 and 2014

Loss before interest and taxes for this segment for the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014 were $6 million , $23 million , and $17 million , respectively.

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All Other

All other includes the Company's investment in Triton, AGL Services Company, and Southern Company Gas Capital, as well as various corporate operating expenses that are not allocated to the reportable segments.

Successor Period of July 1, 2016 through December 31, 2016

Operating expenses included Merger-related expenses of $41 million primarily comprised of compensation-related expenses, financial advisory fees, legal expenses, and other Merger-related costs and $8 million in expenses associated with certain benefit arrangements.

Predecessor Periods of January 1, 2016 through June 30, 2016 and the Years Ended December 31, 2015 and 2014

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, operating expenses included Merger-related expenses of $56 million and $44 million , respectively. These expenses are primarily comprised of financial advisory and legal expenses as well as additional compensation-related expenses, including acceleration of share-based compensation expenses, and change-in-control compensation charges. See Note 11 to the financial statements under "Merger with Southern Company" for additional information.

Segment Reconciliations

Reconciliations of consolidated net income attributable to Southern Company Gas to EBIT for the successor period of July 1, 2016 through December 31, 2016, and operating income to adjusted operating margin for all periods presented, are in the following tables. See Note 12 to the financial statements for additional segment information.

	Successor						
	July 1, 2016 through December 31, 2016						
	Gas Distribution Operations	Gas Marketing Services	Wholesale Gas Services	Gas Midstream Operations	All Other	Intercompany Elimination	Consolidated
	(in millions)						
Consolidated Net Income	$ 77	$ 19	$ —	$ 20	$ (2)	$ —	$ 114
Income taxes	51	7	(3)	16	5	—	76
Interest expense, net of amounts capitalized	105	1	3	16	(44)	—	81
EBIT	$ 233	$ 27	$ —	$ 52	$ (41)	$ —	$ 271

	Successor						
	July 1, 2016 through December 31, 2016						
	Gas Distribution Operations	Gas Marketing Services	Wholesale Gas Services	Gas Midstream Operations	All Other	Intercompany Elimination	Consolidated
	(in millions)						
Operating Income (Loss)	$ 222	$ 27	$ (2)	$ (7)	$ (43)	$ —	$ 197
Other operating expenses [(a)]	626	112	26	26	46	(4)	832
Revenue tax expense [(b)]	(31)	—	—	—	—	—	(31)
Adjusted Operating Margin	$ 817	$ 139	$ 24	$ 19	$ 3	$ (4)	$ 998

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	Predecessor						
	January 1, 2016 through June 30, 2016						
	Gas Distribution Operations	Gas Marketing Services	Wholesale Gas Services	Gas Midstream Operations	All Other	Intercompany Elimination	Consolidated
	(in millions)						
Operating Income (Loss)	**$ 351**	**$ 109**	**$ (69)**	**$ (9)**	**$ (61)**	**$ —**	**$ 321**
Other operating expenses [(a)]	**616**	**81**	**33**	**24**	**65**	**(4)**	**815**
Revenue tax expense [(b)]	**(56)**	**—**	**—**	**—**	**—**	**—**	**(56)**
Adjusted Operating Margin	**$ 911**	**$ 190**	**$ (36)**	**$ 15**	**$ 4**	**$ (4)**	**$ 1,080**

	Predecessor						
	Year Ended December 31, 2015						
	Gas Distribution Operations	Gas Marketing Services	Wholesale Gas Services	Gas Midstream Operations	All Other	Intercompany Elimination	Consolidated
	(in millions)						
Operating Income (Loss)	$ 571	$ 152	$ 112	$ (26)	$ (63)	$ —	$ 746
Other operating expenses [(a)]	1,187	165	71	62	70	(5)	1,550
Revenue tax expense [(b)]	(101)	—	—	—	—	—	(101)
Adjusted Operating Margin	$ 1,657	$ 317	$ 183	$ 36	$ 7	$ (5)	$ 2,195

	Predecessor						
	Year Ended December 31, 2014						
	Gas Distribution Operations	Gas Marketing Services	Wholesale Gas Services	Gas Midstream Operations	All Other	Intercompany Elimination	Consolidated
	(in millions)						
Operating Income (Loss)	$ 573	$ 132	$ 425	$ (19)	$ (16)	$ —	$ 1,095
Other operating expenses [(a)]	1,205	179	79	50	22	(8)	1,527
Gain on disposition of assets	—	—	(3)	—	1	—	(2)
Revenue tax expense [(b)]	(130)	—	—	—	—	—	(130)
Adjusted Operating Margin	$ 1,648	$ 311	$ 501	$ 31	$ 7	$ (8)	$ 2,490

(a) Adjusted for the following operating expenses: other operations and maintenance, depreciation and amortization, taxes other than income taxes, goodwill impairment in 2015, and Merger-related expenses.

(b) Adjusted for Nicor Gas' revenue tax expenses, which are passed through directly to customers.

FUTURE EARNINGS POTENTIAL

General

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 natural gas distribution and its complementary businesses in gas marketing services, wholesale gas services, and gas midstream operations. 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, the completion and subsequent operation of ongoing infrastructure and other construction projects, creditworthiness of customers, the Company's ability to optimize its transportation and storage positions, and its ability to re-contract storage rates at favorable prices. Future earnings will be driven primarily by customer growth, which is subject to a number of factors. These factors include weather, competition, new energy contracts with other utilities, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of natural gas, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territories. Demand for natural gas is primarily driven by economic growth. The pace of economic growth and natural gas demand may be affected by

changes in regional and global economic conditions, which may impact future earnings. Current proposals related to potential tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals is dependent on the final form of any legislation enacted and the related transition rules and cannot be determined at this time, but could have a material impact on the Company's financial statements.

Volatility of natural gas prices has a significant impact on the Company's customer rates, long-term competitive position against other energy sources, and the ability of gas marketing services and wholesale gas services to capture value from locational and seasonal spreads. Additionally, changes in commodity prices subject a significant portion of the Company's operations to earnings variability.

Over the longer term, the Company expects volatility to be low to moderate and locational and/or transportation spreads to decrease as new pipelines are built to reduce the existing supply constraints in the shale areas of the Northeast U.S. To the extent these pipelines are delayed or not built, volatility could increase. Additional economic factors may contribute to this environment, including a significant drop in oil and natural gas prices, which could lead to consolidation of natural gas producers or reduced levels of natural gas production. Further, if economic conditions continue to improve, including the new housing market, the demand for natural gas may increase, which may cause natural gas prices to rise and drive higher volatility in the natural gas markets on a longer term basis.

On September 1, 2016, the Company acquired a 50% equity interest in SNG. See Overview – "Investment in SNG" herein and Notes 4 and 11 to the financial statements under "Equity Method Investments – SNG" and "Investment in SNG," respectively, for additional information.

On October 3, 2016, the Company completed its purchase of Piedmont's 15% interest in SouthStar. See Overview – "Other Matters" herein and Note 4 to the financial statements under "Variable Interest Entities" for additional information.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be recovered in rates on a timely basis or through market-based contracts. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified, as compliance plans are revised or updated, and if legal challenges to rules are completed. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for natural gas, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under " Environmental Matters " for additional information.

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including the handling and disposal of waste and releases of hazardous substances. Compliance with these environmental requirements involves significant capital and operating costs to clean up affected sites. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known impacted sites. The natural gas distribution utilities in Illinois, New Jersey, Georgia, and Florida have each received authority from their respective state regulators to recover approved environmental compliance costs through regulatory mechanisms.

The Company is subject to environmental remediation liabilities associated with former MGP sites in five different states. Accrued environmental remediation costs of $426 million have been recorded in the balance sheets at December 31, 2016 , $69 million of which is expected to be incurred over the next 12 months. These environmental remediation expenditures are recoverable from customers through rate mechanisms approved by the applicable state regulatory agencies, with the exception of one site representing $5 million of the total accrued remediation costs. See FINANCIAL CONDITION AND LIQUIDITY – " Capital Requirements and Contractual Obligations " herein for additional information.

In September 2015, the EPA filed an administrative complaint and notice of opportunity for hearing against Nicor Gas. The complaint alleges violation of the regulatory requirements applicable to polychlorinated biphenyls in the Nicor Gas natural gas distribution system and the EPA seeks a total civil penalty of approximately $0.3 million. On January 26, 2017, the EPA notified Nicor Gas that it agreed to voluntarily dismiss its administrative complaint with prejudice and without payment of a civil penalty or other further obligation on the part of Nicor Gas.

The Company's ultimate environmental compliance strategy and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and the outcome of any legal challenges to the environmental rules. The ultimate outcome of these matters cannot be determined at this time.

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Compliance with any new federal or state legislation or regulations or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the Company's commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for natural gas.

The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. However, the ultimate financial and operational impact of the final rules on the Company cannot be determined at this time and will depend upon numerous factors, including the Company's ongoing review of the final rules; the outcome of legal challenges; individual state implementation of the EPA's final guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; and the time periods over which compliance will be required.

FERC Matters

The Company is involved in three significant pipeline construction projects within gas midstream operations. These projects, along with the Company's existing pipelines, are intended to provide diverse sources of natural gas supplies to customers, resolve current and long-term supply planning for new capacity, enhance system reliability, and generate economic development in the areas served. The following table provides an overview of these pipeline projects.

	Miles of Pipe	Expected Capital Expenditures [a]	Ownership Interest [a]	FERC Filing	Expected FERC Approval
		(in millions)			
Atlantic Coast Pipeline [b]	594	$ 256	5%	2015	2017
PennEast Pipeline [c]	118	270	20%	2015	2017
Dalton Pipeline [d]	115	254	50%	2015	[e]
Total	827	$ 780			

(a) Represents the Company's expected capital expenditures and ownership interest as applicable, which may change.

(b) In 2014, the Company entered into a joint venture to construct and operate a natural gas pipeline that will run from West Virginia through Virginia and into eastern North Carolina to meet the region's growing demand for natural gas. The proposed pipeline project is expected to transport natural gas to customers in Virginia.

(c) In 2014, the Company entered into a joint venture to construct and operate a natural gas pipeline that will transport low-cost natural gas from the Marcellus Shale area to customers in New Jersey. The Company believes this will alleviate takeaway constraints in the Marcellus region and help mitigate some of the price volatility experienced during recent winters.

(d) In 2014, the Company entered into two agreements associated with the construction of the Dalton Pipeline, which will serve as an extension of the Transco pipeline system and provide additional natural gas supply to customers in Georgia. The first is a construction and ownership agreement and the second is an agreement to lease ownership in this lateral pipeline extension once it is placed in service.

(e) The Dalton Pipeline received FERC approval on August 3, 2016, and construction is currently underway.

In addition, on February 3, 2017, SNG filed an application with the FERC for approval of a proposed project, including the purchase of Georgia Power's existing approximately 20-mile McDonough lateral and the construction of a new compressor station, 4.9 miles of new line, and 1.6 miles of pipeline looping. The Company's portion of the expected capital expenditures for this project is approximately $120 million. Georgia Power will subsequently be filing for approval of the sale with the Georgia PSC.

Regulatory Matters

Utility Regulation and Rate Design

The natural gas distribution utilities are subject to regulations and oversight by their respective state regulatory agencies with respect to rates charged to their customers, maintenance of accounting records, and various service and safety matters. Rates charged to customers vary according to customer class (residential, commercial, or industrial) and rate jurisdiction. These agencies approve rates designed to provide the opportunity to generate revenues to recover all prudently incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable return. Rate base generally consists of the original cost of the utility plant in service, working capital, and certain other assets, less accumulated depreciation on the utility plant in service and net deferred income tax liabilities, and may include certain other additions or deductions.

The natural gas market for Atlanta Gas Light was deregulated in 1997. Accordingly, Marketers, rather than a traditional utility, sell natural gas to end-use customers in Georgia and handle customer billing functions. The Marketers file their rates monthly with the Georgia PSC. As a result of operating in a deregulated environment, Atlanta Gas Light's role includes:

- distributing natural gas for Marketers;
- constructing, operating, and maintaining the gas system infrastructure, including responding to customer service calls and leaks;
- reading meters and maintaining underlying customer premise information for Marketers; and
- planning and contracting for capacity on interstate transportation and storage systems.

Atlanta Gas Light earns revenue by charging rates to its customers based primarily on monthly fixed charges that are set by the Georgia PSC and adjusted periodically. The Marketers add these fixed charges when billing customers. This mechanism, called a straight-fixed-variable rate design, minimizes the seasonality of Atlanta Gas Light's revenues since the monthly fixed charge is not volumetric or directly weather dependent.

With the exception of Atlanta Gas Light, the earnings of the natural gas distribution utilities can be affected by customer consumption patterns that are largely a function of weather conditions and price levels for natural gas. Specifically, customer demand substantially increases during the Heating Season when natural gas is used for heating purposes. The Company has various mechanisms, such as weather normalization mechanisms and weather derivative instruments, at most of its utilities that limit exposure to weather changes within typical ranges in these utilities' respective service territories.

With the exception of Atlanta Gas Light, the natural gas distribution utilities are authorized to use natural gas cost recovery mechanisms that allow adjusting rates to reflect changes in the wholesale cost of natural gas and to ensure recovery of all of the costs prudently incurred in purchasing gas for customers. Since Atlanta Gas Light does not sell natural gas directly to its end-use customers, it does not utilize a traditional natural gas cost recovery mechanism. However, Atlanta Gas Light does maintain natural gas inventory for the Marketers in Georgia and recovers the cost through recovery mechanisms approved by the Georgia PSC specific to Georgia's deregulated market. In addition to natural gas recovery mechanisms, there are other cost recovery mechanisms, such as regulatory riders, which vary by utility but allow recovery of certain costs, such as those related to infrastructure replacement programs as well as environmental remediation and energy efficiency plans. In traditional rate designs, utilities recover a significant portion of the fixed customer service and pipeline infrastructure costs based on assumed natural gas volumes used by customers. Three of the utilities have decoupled regulatory mechanisms that encourage conservation. The Company believes that separating, or decoupling, the recoverable amount of these fixed costs from the customer throughput volumes, or amounts of natural gas used by customers, encourages customers' energy conservation and ensures a more stable recovery of fixed costs.

The following table provides regulatory information for the Company's six largest utilities:

	Nicor Gas	Atlanta Gas Light	Elizabethtown Gas	Virginia Natural Gas	Florida City Gas	Chattanooga Gas
Authorized return on equity [(a)]	10.17%	10.75%	10.30%	10.00%	11.25%	10.05%
Weather normalization [(b)]			✓	✓		✓
Decoupled, including straight-fixed-variable rates [(c)]		✓		✓		✓
Regulatory infrastructure program rates [(d)]	✓	✓	✓	✓	✓	
Bad debt rider [(e)]	✓			✓		✓
Synergy sharing policy [(f)]		✓				
Energy efficiency plan [(g)]	✓		✓	✓	✓	✓
Last decision on change in rates	2009	2017 [(h)]	2009 [(i)]	2011 [(j)]	2004	2010

(a) The authorized return on equity represents those authorized at December 31, 2016.

(b) Regulatory mechanisms that allow recovery of costs in the event of unseasonal weather, but are not direct offsets to the potential impacts on earnings of weather and customer consumption. These mechanisms are designed to help stabilize operating results by increasing base rate amounts charged to customers when weather is warmer than normal and decreasing amounts charged when weather is colder than normal.

(c) Recovery of fixed customer service costs separately from assumed natural gas volumes used by customers.

(d) Programs that update or expand distribution systems and LNG facilities.

(e) The recovery (refund) of bad debt expense over (under) an established benchmark expense. Virginia Natural Gas and Chattanooga Gas recover the gas portion of bad debt expense through their purchased gas adjustment mechanisms.

(f) The recovery of 50% of net synergy savings achieved on mergers and acquisitions.

(g) Recovery of costs associated with plans to achieve specified energy savings goals.

(h) The Georgia PSC approved Atlanta Gas Light's petition for the Georgia Rate Adjustment Mechanism (GRAM) on February 21, 2017.

(i) Elizabethtown Gas filed a general rate case with the New Jersey BPU on September 1, 2016, which is scheduled to be resolved during 2017. See Note 3 to the financial statements under "Regulatory Matters – Base Rate Cases" for additional information.

(j) On December 13, 2016, Virginia Natural Gas filed a notice of intent with the Virginia Commission as required at least 60 days prior to the filing of a general base rate case.

Infrastructure Replacement Programs and Capital Projects

The Company continues to focus on capital discipline and cost control while pursuing projects and initiatives that are expected to have current and future benefits to customers, provide an appropriate return on invested capital, and help to ensure the safety and reliability of the utility infrastructure. Total capital expenditures incurred during 2016 for gas distribution operations were $1.1 billion . The following table and discussions provide updates on the infrastructure replacement programs at the utilities, which are designed to update or expand the Company's distribution systems to improve reliability and meet operational flexibility and growth. The anticipated expenditures for these programs in 2017 are quantified in the discussion below.

Utility	Program	Program Details	Recovery	Expenditures in 2016	Expenditures Since Project Inception	Miles of Pipe Installed Since Project Inception	Scope of Program	Program Duration	Last Year of Program
				(in millions)			*(miles)*	*(years)*	
Nicor Gas	Investing in Illinois	(a)(b)	Rider	$ 298	$ 571	343	800	9	2023
Atlanta Gas Light	Integrated Vintage Plastic Replacement Program (i-VPR)	(c)(i)	Rider	71	201	593	756	4	2017
Atlanta Gas Light	Integrated System Reinforcement Program (i-SRP)	(g)(i)	Rider	62	370	n/a	n/a	8	2017
Atlanta Gas Light	Integrated Customer Growth Program (i-CGP)	(h)(i)	Rider	8	71	n/a	n/a	8	2017
Chattanooga Gas	Bare Steel & Cast Iron	(e)	Base Rates	3	40	90	111	10	2020
Florida City Gas	Safety, Access and Facility Enhancement Program (SAFE)	(d)	Rider	11	11	38	250	10	2025
Florida City Gas	Galvanized Replacement Program	(f)	Base Rates	1	16	80	111	17	2017
Virginia Natural Gas	Steps to Advance Virginia's Energy (SAVE and SAVE II)	(a)(j)	Rider	32	122	204	496	10	2021
Elizabethtown Gas	Aging Infrastructure Replacement (AIR)	(e)(k)	Base Rates	22	99	89	130	4	2017
Total				$ 508	$ 1,501	1,437	2,654		

(a) Cast iron, bare steel, mid-vintage plastic, and risk-based materials.

(b) Represents expenditures on qualifying infrastructure that have been placed into service after the rate freeze expiration date, December 9, 2014.

(c) Early vintage plastic, risk-based mid-vintage plastic, and mid-vintage neighborhood convenience.

(d) Four-inch and smaller mains, associated service lines, and in some instances above-ground facilities associated with rear-lot easements.

(e) Cast iron and bare steel.

(f) Galvanized and X-Tube steel. Reflects expenditures and miles of pipe installed since the Company acquired Florida City Gas in 2004.

(g) Large diameter pressure improvement and system reinforcement projects.

(h) New business construction and strategic line extension.

(i) The Georgia PSC approved Atlanta Gas Light's petition for GRAM on February 21, 2017. See Note 3 to the financial statements under "Regulatory Matters – Base Rate Cases" for additional information.

(j) On December 13, 2016, Virginia Natural Gas filed a notice of intent with the Virginia Commission as required at least 60 days prior to the filing of a general base rate case.

(k) Elizabethtown Gas filed a general rate case with the New Jersey BPU on September 1, 2016, which is scheduled to be resolved during 2017. See Note 3 to the financial statements under "Regulatory Matters – Base Rate Cases" for additional information.

Nicor Gas

In 2013, Illinois enacted legislation that allows Nicor Gas to provide more widespread safety and reliability enhancements to its distribution system. The legislation stipulates that rate increases to customer bills as a result of any infrastructure investments shall not exceed an annual average of 4.0% of base rate revenues. In 2014, the Illinois Commission approved the nine-year regulatory infrastructure program, Investing in Illinois, under which Nicor Gas implemented rates that became effective in March 2015. During 2017, Nicor Gas expects to place into service $320 million of qualifying projects under Investing in Illinois.

Atlanta Gas Light

Atlanta Gas Light's four-year STRIDE program, which was approved by the Georgia PSC in 2013, is comprised of i-SRP, i-CGP, and i-VPR, and consists of infrastructure development, enhancement, and replacement programs that are used to update and expand distribution systems and LNG facilities, improve system reliability, and meet operational flexibility and growth. STRIDE includes a monthly surcharge on firm customers that was approved by the Georgia PSC to provide recovery of the revenue requirement for the ongoing programs and the PRP. This surcharge began in January 2015 and will continue through 2025.

The i-SRP program authorized $445 million of capital spending for projects to upgrade Atlanta Gas Light's distribution system and LNG facilities in Georgia, improve its peak-day system reliability and operational flexibility, and create a platform to meet long-term forecasted growth. Under i-SRP, Atlanta Gas Light must file an updated 10-year forecast of infrastructure requirements along with a new construction plan every three years for review and approval by the Georgia PSC. Atlanta Gas Light's most recent plan was approved in 2014. On August 1, 2016, Atlanta Gas Light filed a petition with the Georgia PSC for approval of a four-year extension of its i-SRP seeking approval to invest an additional $177 million to improve and upgrade its core gas distribution system in years 2017 through 2020. Capital investment associated with this filing for 2017 was included in the rate adjustment mechanism approved by the Georgia PSC on February 21, 2017. Capital investment in subsequent years under this filing will be included in future annual GRAM filings. See "Base Rate Cases" herein for additional information. During 2017, Atlanta Gas Light expects to invest $114 million under i-SRP.

The i-CGP program authorized Atlanta Gas Light to spend $91 million on projects to extend its pipeline facilities to serve customers in areas without pipeline access and create new economic development opportunities in Georgia. During 2017, Atlanta Gas Light expects to invest $21 million under i-CGP.

The i-VPR program, which was approved by the Georgia PSC in 2013, authorized Atlanta Gas Light to spend $275 million to replace 756 miles of aging plastic pipe that was installed primarily in the mid-1960s to the early 1980s. Atlanta Gas Light has identified approximately 3,300 miles of vintage plastic mains in its system that should be considered for potential replacement over the next 15 to 20 years under this program. During 2017, Atlanta Gas Light expects to invest $80 million under i-VPR.

In conjunction with a joint stipulation associated with the annual rate adjustment mechanism approved by the Georgia PSC on February 21, 2017, Atlanta Gas Light's surcharges associated with the STRIDE programs will be included in base rates. See "Base Rate Cases" herein for additional information.

Elizabethtown Gas

Elizabethtown Gas' extension of the AIR enhanced infrastructure program effective in 2013 allowed for infrastructure investment of $115 million over four years, and is focused on the replacement of aging cast iron in its pipeline system. Carrying charges on the additional capital spend are being accrued and deferred for regulatory purposes at a WACC of 6.65%. In conjunction with the general base rate case filed with the New Jersey BPU on September 1, 2016, Elizabethtown Gas requested recovery of the AIR program. See "Base Rate Cases" herein for additional information. During 2017, Elizabethtown Gas expects to invest $10 million under this program.

In 2014, the New Jersey BPU approved Natural Gas Distribution Utility Reinforcement Effort (ENDURE), a program that improved Elizabethtown Gas' distribution system's resiliency against coastal storms and floods. Under the plan, Elizabethtown Gas invested $15 million in infrastructure and related facilities and communication planning over a one-year period from August 2014 through September 2015. Effective November 2015, Elizabethtown Gas increased its base rates for investments made under the program.

In September 2015, Elizabethtown Gas filed the Safety, Modernization and Reliability Tariff (SMART) plan with the New Jersey BPU seeking approval to invest more than $1.1 billion to replace 630 miles of vintage cast iron, steel, and copper pipeline, as well as 240 regulator stations. If approved, the program is expected to be completed by 2027. As currently proposed, costs incurred under the program would be recovered through a rider surcharge over a period of 10 years. The New Jersey BPU is expected to issue an order on this filing in 2017.

The ultimate outcome of these matters cannot be determined at this time.

Virginia Natural Gas

In 2012, the Virginia Commission approved the SAVE program, an accelerated infrastructure replacement program, to be completed over a five -year period. This program includes a maximum allowance for capital expenditures of $25 million per year, not to exceed $105 million in total. SAVE is subject to annual review by the Virginia Commission. Virginia Natural Gas is recovering these program costs through a rate rider that became effective in 2012.

On March 9, 2016, the Virginia Commission approved an extension to the SAVE program to replace more than 200 miles of aging pipeline infrastructure. In accordance with the order approving the program, Virginia Natural Gas may invest up to $35 million annually through 2021. Additionally, Virginia Natural Gas may exceed the allowed program expenditures by up to a total of $5 million , of which $2 million was used in 2016. During 2017, Virginia Natural Gas expects to invest $35 million under this program.

Florida City Gas

In September 2015, the Florida PSC approved Florida City Gas' SAFE program, under which costs incurred for replacing aging pipes will be recovered through a rate rider with annual adjustments and true-ups. Under the program, Florida City Gas is authorized to spend $105 million over a 10-year period on infrastructure relocation and enhancement projects. During 2017, Florida City Gas expects to invest $10 million under this program.

See Note 3 to the financial statements under " Regulatory Matters " for additional information regarding rate mechanisms and accounting orders.

Natural Gas Cost Recovery

The Company has established natural gas cost recovery rates that are approved by the relevant regulatory agencies of the states in which it serves. Natural gas cost recovery revenues are adjusted for differences in actual recoverable natural gas costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on the Company's revenues or net income, but will affect cash flows. See Note 3 to the financial statements under " Regulatory Matters " for additional information.

Base Rate Cases

On December 5, 2016, Atlanta Gas Light filed a joint stipulation with the staff of the Georgia PSC seeking an annual rate review/adjustment mechanism, GRAM. This new mechanism will adjust rates up or down annually and will not collect revenue through special riders and surcharges for the STRIDE infrastructure programs. Also in this filing, Atlanta Gas Light requested an adjustment in base rates designed to collect an additional $20 million in annual revenues effective March 2017. On February 21, 2017, the Georgia PSC approved the joint stipulation and requested base rate adjustment.

On September 1, 2016, Elizabethtown Gas filed a general base rate case with the New Jersey BPU as required under its AIR program, requesting an increase in annual revenues of $19 million , based on an allowed ROE of 10.25% . The Company expects the New Jersey BPU to issue an order on the filing in the third quarter 2017.

On December 13, 2016, Virginia Natural Gas filed a notice of intent with the Virginia Commission as required at least 60 days prior to filing a general base rate case.

The ultimate outcome of these matters cannot be determined at this time.

Asset Management Agreements

Six of the Company's utilities use asset management agreements with the Company's wholly-owned subsidiary, Sequent, for the primary purpose of reducing utility customers' gas cost recovery rates through payments to the utilities by Sequent. Nicor Gas has not entered into an asset management agreement with Sequent or any other parties. For Atlanta Gas Light, these payments are controlled by the Georgia PSC and are utilized for infrastructure improvements and to fund heating assistance programs, rather than as a reduction to gas cost recovery rates. Under these asset management agreements, Sequent supplies natural gas to the utility and markets available pipeline and storage capacity to improve the overall cost of supplying gas to the utility customers. Currently, the Company's utilities primarily purchase their gas from Sequent. The purchase agreements require Sequent to provide firm gas to the Company's utilities, but these utilities maintain the right and ability to make their own gas supply purchases. This right allows the Company's utilities to make long-term supply arrangements if they believe it is in the best interest of their customers.

Each agreement provides for Sequent to make payments to the utilities through either an annual minimum guarantee within a profit sharing structure, a profit sharing structure without an annual minimum guarantee, or a fixed fee. From the inception of

these agreements in 2001 through December 31, 2016, Sequent made sharing payments to the Company's utilities under these agreements totaling $367 million. On April 14, 2016, as part of its approval order for the Merger, the Georgia PSC approved an extension of Atlanta Gas Light's asset management agreement with Sequent to March 31, 2020.

The following table provides payments made by Sequent to the Company's utilities under these agreements during the last three years:

	Successor	Predecessor			
	Total Amount Received	Total Amount Received			
	July 1, 2016 through December 31,	**January 1, 2016 through June 30,**	Years Ended December 31,		
	2016	**2016**	2015	2014	Expiration Date
	(in millions)	*(in millions)*			
Elizabethtown Gas	**$ 3**	**$ 12**	$ 28	$ 18	Mar-19
Virginia Natural Gas	**2**	**9**	15	14	Mar-18
Atlanta Gas Light	**1**	**6**	15	13	Mar-20
Florida City Gas	**—**	**1**	1	1	(*)
Chattanooga Gas	**—**	**1**	1	1	Mar-18
Total	**$ 6**	**$ 29**	$ 60	$ 47	

(*) The agreement renews automatically each year unless terminated by either party.

PRP Settlement

In October 2015, Atlanta Gas Light received a final order from the Georgia PSC, which represented a resolution of all matters previously outstanding before the Georgia PSC, including a final determination of the true-up of allowed unrecovered revenue through December 2014. This order allows Atlanta Gas Light to recover $144 million of the $178 million unrecovered program revenue that was requested in its February 2015 filing. The remaining unrecovered amount related primarily to the previously unrecognized ratemaking amount and did not have a material impact on the Company's consolidated financial statements. The Company also recognized $1 million of interest expense and $5 million in operations and maintenance expense related to the PRP on the Company's consolidated statements of income for the predecessor year ended December 31, 2015. See "Unrecognized Ratemaking Amounts" herein for additional information.

Atlanta Gas Light began recovering $144 million in October 2015 through the monthly PRP surcharge of $0.82 , or approximately $15 million annually, which increased by $0.81 on October 1, 2016. The monthly PRP surcharge is scheduled to increase by another $0.81 on October 1, 2017. As part of the Georgia PSC's approval, this increase will commence earlier with its implementation under GRAM. The PRP surcharge will remain effective until the earlier of the full recovery of the under-recovered amount or December 31, 2025. See "Base Rate Cases" herein for additional information on GRAM.

One of the capital projects under the PRP experienced construction issues and Atlanta Gas Light was required to complete mitigation work prior to placing it in service. These mitigation costs will be included in future base rates in 2018. Provisions in the order resulted in the recognition of $5 million in operations and maintenance expense for the year ended December 31, 2015 on the Company's consolidated statements of income. Atlanta Gas Light continues to pursue contractual and legal claims against certain third-party contractors and will retain any amounts recorded.

Gas Cost Prudence Review

In 2014, the Illinois Commission staff and the CUB filed testimony in the Nicor Gas 2003 gas cost prudence review disputing certain gas loan transactions offered by Nicor Gas under its Chicago Hub services and requesting refunds of $18 million and $22 million , respectively. On February 10, 2016, the administrative law judge issued a proposed order affirming an original order by the Illinois Commission, which was approved by the Illinois Commission on March 23, 2016 and concluded this matter. The Illinois Commission approved the purchase gas adjustments for the years 2004 through 2007 on August 9, 2016 and for the years 2008 and 2009 on August 24, 2016. As a condition of these approvals, Nicor Gas agreed to revise the way in which interest is reflected in the calculations beginning in 2013. The Company does not expect this revision to have a material impact on its consolidated financial statements. The gas cost prudence reviews for years 2010 through 2015 are underway. The ultimate outcome of these matters cannot be determined at this time.

energySMART

In 2014, the Illinois Commission approved Nicor Gas' energySMART, which outlines energy efficiency program offerings and therm reduction goals with spending of $93 million over a three -year period that began in 2014. On December 7, 2016, new energy legislation was signed in Illinois that extended the current program through December 31, 2017, with a new total expenditure of approximately $110 million.

Unrecognized Ratemaking Amounts

The following table illustrates the Company's authorized ratemaking amounts that are not recognized on its balance sheets. These amounts are primarily composed of an allowed equity rate of return on assets associated with certain of the Company's regulatory infrastructure programs. These amounts will be recognized as revenues in the Company's consolidated financial statements in the periods they are billable to customers.

	Successor	Predecessor
	December 31, 2016	December 31, 2015
	(in millions)	*(in millions)*
Atlanta Gas Light	$ 110	$ 103
Virginia Natural Gas	11	12
Elizabethtown Gas	6	4
Nicor Gas	2	3
Total	$ 129	$ 122

Income Tax Matters

Bonus Depreciation

In December 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service through 2020. The PATH Act allows for 50% bonus depreciation for 2015 through 2017, 40% bonus depreciation for 2018, and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. The extension of bonus depreciation included in the PATH Act is expected to result in approximately $60 million of positive cash flows for the 2016 tax year, which was not all realized in 2016 due to a projected consolidated net operating loss for Southern Company. Approximately $260 million of positive cash flows is expected to result from bonus depreciation for the 2017 tax year, but may not be realized in 2017 due to the additional net operating loss projections for the 2017 tax year. The ultimate outcome of this matter cannot be determined at this time.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business.

Nicor Gas and Nicor Energy Services Company, wholly-owned subsidiaries of the Company, and Nicor Inc. are defendants in a putative class action initially filed in 2011 in state court in Cook County, Illinois. The plaintiffs purport to represent a class of the customers who purchased the Gas Line Comfort Guard product from Nicor Energy Services Company and variously allege that the marketing, sale, and billing of the Gas Line Comfort Guard product violated the Illinois Consumer Fraud and Deceptive Business Practices Act, constituting common law fraud and resulting in unjust enrichment of these entities. The plaintiffs seek, on behalf of the classes they purport to represent, actual and punitive damages, interest, costs, attorney fees, and injunctive relief. On February 8, 2017, the judge denied the plaintiffs' motion for class certification and the Company's motion for summary judgment. The ultimate outcome of this matter cannot be determined at this time.

The Company is assessing its alleged involvement in an incident that occurred in one of its service territories that resulted in several deaths, injuries, and property damage. One of the Company's utilities has been named as one of the defendants in several lawsuits related to this incident. The Company has insurance that provides full coverage of any financial exposure in excess of $11 million related to this incident. During the successor period ended December 31, 2016 and the predecessor period ended December 31, 2015, the Company recorded reserves for substantially all of its potential exposure from these cases. The ultimate outcome of this matter cannot be determined at this time.

The ultimate outcome of these matters and such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does

not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements under "General Litigation Matters" 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's seven natural gas utilities comprised approximately 80% of the Company's total operating revenues for 2016 and are subject to rate regulation by their respective state regulatory agencies, which set the rates utilities are permitted to charge customers based on allowable costs, including a reasonable ROE. As a result, the utilities apply accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the utilities; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and other postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Pushdown of Acquisition Accounting

Southern Company has pushed down the application of the acquisition method of accounting to the Company's consolidated financial statements. The acquisition method of accounting requires the assets acquired and liabilities assumed in an acquired business to be recorded at their estimated fair values on the date of acquisition. The difference between the purchase price amount and the net fair value of assets acquired and liabilities assumed is recognized as goodwill on the balance sheet if it exceeds the estimated fair value and as a bargain purchase gain on the income statement if it is below the estimated fair value. Determining the fair value of assets acquired and liabilities assumed requires management's judgment, often utilizes independent valuation experts, and involves the use of significant estimates and assumptions with respect to the timing and amounts of future cash inflows and outflows, discount rates, market prices, and asset lives, among other items. The judgments made in the determination of the estimated fair value assigned to the assets acquired and liabilities assumed, as well as the estimated useful life of each asset and the duration of each liability, can materially impact the financial statements in periods after the Merger, such as through depreciation and amortization and interest expense. See Note 11 to the financial statements for additional information.

Given the significant judgment involved in estimating the fair values of assets acquired and liabilities assumed, the Company considers acquisition accounting to be a critical accounting estimate.

Assessment of Assets

Goodwill

The Company does not amortize its goodwill, but tests it annually for impairment at the reporting unit level during the fourth quarter or more frequently if impairment indicators arise. These indicators include, but are not limited to, a significant change in operating performance, the business climate, legal or regulatory factors, or a planned sale or disposition of a significant portion of the business. A reporting unit is the operating segment, or a business one level below the operating segment (a component), if discrete financial information is prepared and regularly reviewed by management. Components are aggregated if they have similar economic characteristics.

As part of the Company's impairment test, the Company may perform an initial qualitative Step 0 assessment to determine whether it is more likely than not that the fair value of each reporting unit is less than its carrying amount before applying the two-step, quantitative goodwill impairment test. If the Company elects to perform the qualitative assessment, it evaluates relevant events and circumstances, including but not limited to, macroeconomic conditions, industry and market conditions, cost factors, financial performance, entity specific events, and events specific to each reporting unit. If the Company determines that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, or it elects not to perform a qualitative assessment, it performs the two-step goodwill impairment test.

Step 1 of the two-step goodwill impairment test compares the fair value of the reporting unit to its carrying value. If the result of the Step 1 test reveals that the estimated fair value is below its carrying value, the Company proceeds with Step 2.

Step 2 of the goodwill impairment test compares the implied fair value of goodwill, which is calculated as the residual amount from the reporting unit's overall fair value after assigning fair values to its assets and liabilities under a hypothetical purchase price allocation as if the reporting unit had been acquired in a business combination, to its carrying value. Based on the result of the Step 2 test, the Company records a goodwill impairment charge for any excess of carrying value over the implied fair value of goodwill.

For the 2016 and 2015 annual impairment tests, the Company performed the qualitative Step 0 assessment described above and determined that it was more likely than not that the fair value of all of its reporting units with goodwill exceeded their carrying amounts, and therefore no quantitative analysis was required. For the 2014 annual impairment test, the Company performed Step 1 of the two-step impairment test, which resulted in the fair value of all of its reporting units exceeding their carrying value.

In the third quarter 2015 , the Company identified potential impairment indicators and performed an interim impairment test for its storage and fuels reporting unit, which resulted in impairment of the full $14 million goodwill balance for that reporting unit.

As the determination of an asset's fair value and useful life involves management making certain estimates and because these estimates form the basis for the determination of whether or not an impairment charge should be recorded, the Company considers these estimates to be critical accounting estimates.

Long-Lived Assets

The Company depreciates or amortizes its long-lived and intangible assets over their estimated useful lives. The Company assesses its long-lived and intangible assets for impairment whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. When such events or circumstances are present, the Company assesses the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. Impairment is indicated if the carrying amount of a long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If impairment is indicated, the Company records an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset.

As the determination of the expected future cash flows generated from an asset, an asset's fair value, and useful life involves management making certain estimates and because these estimates form the basis for the determination of whether or not an impairment charge should be recorded, the Company considers these estimates to be critical accounting estimates.

Derivatives and Hedging Activities

Determining whether a contract meets the definition of a derivative instrument, contains an embedded derivative requiring bifurcation, or qualifies for hedge accounting treatment is voluminous and complex. The treatment of a single contract may vary from period to period depending upon accounting elections, changes in the Company's assessment of the likelihood of future hedged transactions, or new interpretations of accounting guidance. As a result, judgment is required in determining the appropriate accounting treatment. In addition, the estimated fair value of derivative instruments may change significantly from period to period depending upon market conditions and changes in hedge effectiveness may impact the accounting treatment.

Derivative instruments (including certain derivative instruments embedded in other contracts) are recorded on the balance sheets as either assets or liabilities measured at their fair value. Unless the transaction qualifies for, and is designated as, a normal purchase or normal sale, it is exempted from fair value accounting treatment and is, instead, subject to traditional accrual accounting. The Company utilizes market data or assumptions that market participants would use in pricing the derivative asset or liability, including assumptions about risk and the risks inherent in the inputs of the valuation technique.

Changes in the derivatives' fair value are recognized concurrently in earnings unless specific hedge accounting criteria are met. If the derivatives meet those criteria, derivative gains and losses offset related results of the hedged item in the income statement in the case of a fair value hedge, or gains and losses are recorded in OCI on the balance sheets until the hedged transaction affects

earnings in the case of a cash flow hedge. Additionally, a company is required to formally designate a derivative as a hedge as well as document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting treatment.

Nicor Gas and Elizabethtown Gas utilize derivative instruments to hedge the price risk for the purchase of natural gas for customers. These derivatives are reflected at fair value and are not designated as accounting hedges. Realized gains or losses on such instruments are included in the cost of gas delivered and are passed through directly to customers, subject to review by the applicable state regulatory agencies, and therefore have no direct impact on earnings. Unrealized changes in the fair value of these derivative instruments are deferred as regulatory assets or liabilities.

The Company uses derivative instruments primarily to reduce the impact to its results of operations due to the risk of changes in the price of natural gas and to a lesser extent the Company hedges against warmer-than-normal weather and interest rates. The fair value of natural gas derivative instruments used to manage exposure to changing natural gas prices reflects the estimated amounts that the Company would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. For derivatives utilized at gas marketing services and wholesale gas services that are not designated as accounting hedges, changes in fair value are reported as gains or losses in the Company's results of operations in the period of change. Gas marketing services records derivative gains or losses arising from cash flow hedges in OCI and reclassifies them into earnings in the same period that the underlying hedged item is recognized in earnings.

The Company classifies derivative assets and liabilities based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. The determination of the fair value of the derivative instruments incorporates various required factors. These factors include:

- the creditworthiness of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit);
- events specific to a given counterparty; and
- the impact of the Company's nonperformance risk on its liabilities.

If there is a significant change in the underlying market prices or pricing assumptions the Company uses in pricing its derivative assets or liabilities, the Company may experience a significant impact on its financial position, results of operations, and cash flows. See Note 10 to the financial statements for additional information.

Given the assumption used in pricing the derivative asset or liability, the Company considers the valuation of derivative assets and liabilities a critical accounting estimate. See FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" herein for more information.

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, the Company discounts the future related cash flows using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. For 2015 and 2014, the Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. For the successor period of July 1, 2016 through December 31, 2016 and the predecessor period of January 1, 2016 through June 30, 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 $ 7 million in 2016 .

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $4 million or less change in total annual benefit expense, a $38 million or less change in projected obligations for the pension plans, a $1 million or less change in total annual benefit expense, and an $8 million or less change in projected obligations for the other postretirement benefit plan.

See Note 2 to the financial statements for additional information regarding pension and other postretirement benefits.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations as well as other factors and conditions that subject it to environmental, litigation, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's results of operations, cash flows, or financial condition.

Recently Issued Accounting Standards

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers,* replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

While the Company expects most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of such arrangements. The majority of the Company's revenue, including energy provided to customers, is from tariff offerings that provide natural gas without a defined contractual term. For such arrangements, the Company generally expects that the revenue from contracts with these customers will continue to be equivalent to the natural gas supplied and billed in that period (including unbilled revenues) and the adoption of ASC 606 will not result in a significant shift in the timing of revenue recognition for such sales.

The Company's ongoing evaluation of other revenue streams and related contracts includes longer term contractual commitments and unregulated sales to customers. Some revenue arrangements, such as certain alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on the Company's financial statements. In addition, the power and utilities industry is currently addressing other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). If final implementation guidance indicates CIAC will be accounted for under ASC 606 and offsetting regulatory treatment is not permitted, it could have a material impact on the Company's financial statements.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. The Company must select a transition method to be applied either retrospectively to each prior reporting period presented or retrospectively with a cumulative effect adjustment to retained earnings at the date of initial adoption. As the ultimate impact of the new standard has not yet been determined, the Company has not elected its transition method.

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, the Company elected to early adopt the guidance in 2016. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of the Company.

On February 25, 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged and there is no change to the accounting for existing leveraged leases. ASU 2016-02 is effective for fiscal years beginning after December 15,

2018, with early adoption permitted. The Company is currently evaluating the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

On March 30, 2016, the FASB issued ASU No. 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Note 5 to the financial statements for the disclosure impacted by ASU 2016-09.

On October 24, 2016, the FASB issued ASU No. 2016-16, *Income Taxes (Topic 740), Intra-Entity Transfers of Assets Other Than Inventory* (ASU 2016-16). Current GAAP prohibits the recognition of current and deferred income taxes for an affiliate asset transfer until the asset has been sold to an outside party. ASU 2016-16 requires an entity to recognize the income tax consequences of an affiliate transfer of an asset other than inventory when the transfer occurs. ASU 2016-16 is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. The amendments will be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The Company is currently assessing the impact of the standard on its financial statements.

On November 17, 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* (ASU 2016-18). ASU 2016-18 eliminates the need to reflect transfers between cash and restricted cash in operating, investing, and financing activities in the statement of cash flows. Upon adoption, the net change in cash and cash equivalents during the period will include amounts generally described as restricted cash or restricted cash equivalents. ASU 2016-18 is effective for fiscal years beginning after December 15, 2017, with early adoption permitted, and will be applied retrospectively to each period presented. The Company does not intend to adopt the guidance early. The adoption of ASU 2016-18 will not have a material impact on the financial statements of the Company.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2016. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to maintain existing natural gas distribution systems as well as to update and expand these systems, and to comply with environmental regulations. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2017 through 2019, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt issuances and equity contributions from Southern Company. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as 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.

By regulation, Nicor Gas is restricted, to the extent of its retained earnings balance, in the amount it can dividend or loan to affiliates and is not permitted to make money pool loans to affiliates. Elizabethtown Gas is restricted by its dividend policy as established by the New Jersey BPU in the amount it can dividend to its parent company to the extent of 70% of its quarterly net income. Additionally, as stipulated in the New Jersey BPU's order approving the Merger, the Company is prohibited from paying dividends to its parent company, Southern Company, if the Company's senior unsecured debt rating falls below investment grade. At December 31, 2016 , the amount of subsidiary retained earnings and net income restricted to dividend totaled $688 million .

The Company's investments in the qualified pension plan increased in value at December 31, 2016 as compared to December 31, 2015 . On September 12, 2016, the Company voluntarily contributed $125 million to its qualified pension plan. No mandatory contributions to its qualified pension plan are anticipated during 2017 . See Note 2 to the financial statements under "Retirement Benefits" for additional information.

Net cash used for operating activities was $328 million for the successor period of July 1, 2016 through December 31, 2016 , which reflected a $125 million voluntary pension contribution, a $35 million payment for the settlement of an interest rate swap, and less cash due to the timing of collection of receivables and disbursement of payables. Due to the seasonal nature of its business, the Company typically reports negative cash flows from operating activities in the second half of the year. Net cash provided from operating activities was $1.1 billion for the predecessor period of January 1, 2016 through June 30, 2016 , which reflected low volumes of natural gas sales and changes in natural gas inventory as a result of warmer weather and the timing of recovery of related gas costs and weather normalization adjustments from customers. Net cash provided from operating activities was $1.4 billion and $655 million for the predecessor years ended December 31, 2015 and 2014 , respectively, which represents an increase of $726 million due to (i) higher working capital needs during 2014 resulting from higher natural gas prices and volumes delivered as well as the timing of recoveries of related gas costs from customers, (ii) cash provided from derivative financial instrument assets and liabilities primarily as a result of the decrease in forward NYMEX prices, and (iii) a 2014 tax refund of $150 million received in January 2015 related to the extension of bonus depreciation. These increases were partially offset by lower earnings, largely attributable to warmer weather compared to 2014 , and net cash provided by energy marketing receivables and payables.

Net cash used for investing activities was $2.1 billion for the successor period of July 1, 2016 through December 31, 2016 , which reflected $1.4 billion primarily related to the Company's acquisition of the 50% interest in SNG, and $632 million in capital expenditures. Net cash used for investing activities was $559 million for the predecessor period of January 1, 2016 through June 30, 2016 , primarily related to $548 million in capital expenditures. Net cash used for investing activities was $1.0 billion and $505 million for the predecessor years ended December 31, 2015 and 2014 , respectively, which reflected capital expenditures of $1.0 billion in 2015 and $769 million in 2014 , partially offset by $225 million in proceeds from the sale of Tropical Shipping in 2014 .

Net cash provided from financing activities was $2.4 billion for the successor period of July 1, 2016 through December 31, 2016 , which reflected $1.1 billion of capital contributions from Southern Company, primarily used to fund the Company's investment in SNG, $1.1 billion in net additional commercial paper borrowings, partially offset by $160 million for the purchase of the 15% noncontrolling ownership interest in SouthStar, and $900 million in proceeds from debt issuances, partially offset by $420 million in debt payments. Net cash used for financing activities was $558 million for the predecessor period of January 1, 2016 through June 30, 2016 due to $896 million in net repayment of commercial paper borrowings and $125 million in repayment of long-term debt, partially offset by $600 million in debt issuances. Net cash used for financing activities was $366 million and $224 million for the predecessor years ended December 31, 2015 and 2014 , respectively, which reflected an increase of $142 million due to the net repayment of commercial paper borrowings during 2015 , partially offset by the proceeds from debt issuances in 2015 in excess of debt repayments.

The application of acquisition accounting during 2016 changed the basis of certain assets and liabilities. See Note 11 to the financial statements under "Merger with Southern Company" for additional information. In addition to the impacts of acquisition accounting, significant balance sheet changes at December 31, 2016 included increases of $951 million in long-term debt, including debt due within one year, primarily related to issuances of senior notes and first mortgage bonds, $1.5 billion in equity investments in unconsolidated subsidiaries primarily related to the investment in SNG, and $774 million in property, plant, and equipment due to capital expenditures at gas distribution operations, as well as an increase of $247 million in notes payable primarily due to increased spending on infrastructure replacement programs.

Sources of Capital

The Company plans to obtain the funds to meet its future capital needs through operating cash flows, short-term borrowings, securities issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, depend upon prevailing market conditions, regulatory approval, and other factors.

The issuance of securities by Nicor Gas is generally subject to the approval of the Illinois Commission.

The Company obtains financing separately without credit support from any affiliate in the Southern Company system. 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, except as described below, funds of the Company are not commingled with funds of any other company in the Southern Company system.

The Company maintains commercial paper programs at Southern Company Gas Capital and Nicor Gas that consist of short-term, unsecured promissory notes. Nicor Gas' commercial paper program supports its working capital needs as Nicor Gas is not permitted to make money pool loans to affiliates. All of the Company's other subsidiaries benefit from Southern Company Gas Capital's commercial paper program.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company Gas and Subsidiary Companies 2016 Annual Report

At December 31, 2016 , the Company's current liabilities exceeded current assets by $668 million . The Company's current liabilities frequently exceed current assets because of commercial paper borrowings, long-term debt that is due within one year, and cash needs, which can fluctuate significantly due to the seasonality of the business.

At December 31, 2016 , the Company had $19 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2016 were as follows:

	Expires				Expires Within One Year	
Company	**2017**	**2018**	**Total**	**Unused**	**Term Out**	**No Term Out**
	(in millions)		*(in millions)*		*(in millions)*	
Southern Company Gas Capital (*)	$ 49	$ 1,251	$ 1,300	$ 1,249	$ —	$ 49
Nicor Gas	26	674	700	700	—	26
Total	$ 75	$ 1,925	$ 2,000	$ 1,949	$ —	$ 75

(*) Southern Company Gas guarantees the obligations of Southern Company Gas Capital.

Pivotal Utility Holdings is party to a series of loan agreements with the New Jersey Economic Development Authority and Brevard County, Florida under which five series of gas facility revenue bonds have been issued totaling approximately $200 million .

See Note 6 to the financial statements under " Bank Credit Arrangements " for additional information.

The Southern Company Gas Credit Facility and the Nicor Gas Credit Facility included in the table above each contain a covenant that limits the ratio of debt to capitalization (as defined in each Facility) to a maximum of 70% and contain cross acceleration provisions to other indebtedness (including guarantee obligations) of the applicable company. Such cross acceleration provisions to other indebtedness would trigger an event of default if the applicable company defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2016, each of the applicable companies were in compliance with all such covenants. Neither of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

Subject to applicable market conditions, the applicable company expects to renew or replace its bank credit arrangements, as needed, prior to expiration. In connection therewith, the applicable company may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

The Company has substantial cash flow from operating activities and access to the capital markets, including commercial paper programs, to meet liquidity needs. The Company makes short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. Commercial paper borrowings are included within notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (*)		
	Amount Outstanding	Weighted Average Interest Rate	Average Amount Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
Successor – December 31, 2016:					
Southern Company Gas Capital	**$ 733**	**1.09%**	**$ 309**	**0.67%**	**$ 770**
Nicor Gas	**524**	**0.95%**	**461**	**0.79%**	**587**
Total	**$ 1,257**	**1.03%**	**$ 770**	**0.74%**	
Predecessor – December 31, 2015:					
Southern Company Gas Capital	$ 471	0.71%	$ 382	0.49%	$ 787
Nicor Gas	539	0.52%	349	0.38%	585
Total	$ 1,010	0.60%	$ 731	0.44%	
Predecessor – December 31, 2014:					
Southern Company Gas Capital	$ 590	0.48%	$ 399	0.33%	$ 1,006
Nicor Gas	585	0.44%	279	0.25%	614
Total	$ 1,175	0.46%	$ 678	0.29%	

(*) Average and maximum amounts are based upon daily balances during the successor period of July 1, 2016 through December 31, 2016 and the predecessor years ended December 31, 2015 and 2014 .

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

The long-term debt on the Company's consolidated balance sheets includes both principal and non-principal components. At December 31, 2016 , the non-principal component was $569 million , which consisted of the unamortized portions of the fair value adjustment recorded in purchase accounting, debt premiums, debt discounts, and debt issuance costs.

In February and May 2016, $75 million and $50 million , respectively, of Nicor Gas' first mortgage bonds matured and were repaid using the proceeds from commercial paper borrowings.

In May 2016, Southern Company Gas Capital issued $350 million aggregate principal amount of 3.250% Senior Notes due June 15, 2026, which are guaranteed by Southern Company Gas. The proceeds were used to repay at maturity $300 million aggregate principal amount of 6.375% Senior Notes due July 15, 2016 and for general corporate purposes.

In June 2016, Nicor Gas issued $250 million aggregate principal amount of first mortgage bonds with the following terms: $100 million at 2.66% due June 20, 2026, $100 million at 2.91% due June 20, 2031, and $50 million at 3.27% due June 20, 2036. The proceeds were used to repay short-term indebtedness incurred under the Nicor Gas commercial paper program and for other working capital needs.

In September 2016, Southern Company Gas Capital issued $350 million aggregate principal amount of 2.45% Senior Notes due October 1, 2023 and $550 million aggregate principal amount of 3.95% Senior Notes due October 1, 2046, both of which are guaranteed by Southern Company Gas. The proceeds were used to repay a $360 million promissory note issued to Southern Company for the purpose of funding a portion of the purchase price for a 50% equity interest in SNG, to fund the purchase of Piedmont's interest in SouthStar, to make a voluntary contribution to the pension plan, to repay at maturity $120 million aggregate principal amount of Series A Floating Rate Senior Notes due October 27, 2016, and for general corporate purposes.

A portion of the purchase price of the Company's investment in SNG was funded by a $1.05 billion equity contribution from Southern Company received in September 2016. See Note 4 to the financial statements under " Investment in SNG " for additional information.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change below BBB- and/or Baa3. These contracts are for physical gas purchases and sales and energy price risk management. The maximum potential collateral requirements under these contracts at December 31, 2016 was $26 million .

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of the Company to access capital markets and would be likely to impact the cost at which it does so.

On May 12, 2016, Fitch revised its ratings outlook for the Company from positive to stable.

On July 11, 2016, in conjunction with the close of the Merger, S&P raised the Company's and Nicor Gas' corporate and senior unsecured long-term debt ratings from BBB+ to A- and revised their ratings outlooks from positive to negative.

On January 10, 2017, S&P revised its consolidated credit rating outlook for Southern Company (including the Company) from negative to stable.

Market Price Risk

The Company is exposed to market risks, primarily commodity price risk, interest rate risk, and weather risk. Due to various cost recovery mechanisms, the natural gas distribution utilities of the Company that sell natural gas directly to end-use customers have limited exposure to market volatility of natural gas prices. 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 uses derivatives to buy and sell natural gas as well as 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 $200 million of long-term variable interest rate exposure at January 1, 2017 was 1.28% . If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would have an immaterial effect on annualized interest expense at January 1, 2017 . See Note 1 to the financial statements under " Financial Instruments " and Note 10 to the financial statements for additional information.

Gas marketing services and wholesale gas services routinely utilize various types of derivative instruments to mitigate certain natural gas price and weather risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and over-the-counter (OTC) energy contracts, such as forward contracts, futures contracts, options contracts, and swap agreements. Gas marketing services and wholesale gas services also actively manage storage positions through a variety of hedging transactions for the purpose of managing exposures arising from changing natural gas prices. These hedging instruments are used to substantially protect economic margins (as spreads between wholesale and retail natural gas prices widen between periods) and thereby minimize exposure to declining operating margins.

Certain natural gas distribution utilities of the Company manage fuel-hedging programs implemented per the guidelines of their respective state regulatory agencies to hedge the impact of market fluctuations in natural gas prices for customers. For the weather risk associated with Nicor Gas, the Company has a corporate weather hedging program that utilizes weather derivatives to reduce the risk of lower adjusted operating margins potentially resulting from significantly warmer-than-normal weather. In addition, certain non-regulated operations routinely utilize various types of derivative instruments to economically hedge certain commodity price and weather risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and OTC energy contracts, such as forward contracts, futures contracts, options contracts, and swap agreements. Some of these economic hedge activities may not qualify, or are not designated, for hedge accounting treatment. The Company had no material change in market risk exposure during 2016 .

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company Gas and Subsidiary Companies 2016 Annual Report

For the periods presented below, the changes in net fair value of derivative contracts were as follows:

	Successor	Predecessor		
	July 1, 2016 through December 31,	January 1, 2016 through June 30,	Years Ended December 31,	
	2016	2016	2015	2014
	(in millions)	*(in millions)*		
Contracts outstanding at beginning of period, assets (liabilities), net	**$ (54)**	**$ 75**	$ 61	$ (82)
Contracts realized or otherwise settled	**18**	**(77)**	(17)	38
Current period changes [(a)]	**48**	**(82)**	32	105
Contracts outstanding at the end of period, assets (liabilities), net	**12**	**(84)**	76	61
Netting of cash collateral	**62**	**120**	96	133
Cash collateral and net fair value of contracts outstanding at end of period [(b)]	**$ 74**	**$ 36**	$ 172	$ 194

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

(b) Net fair value of derivative contracts outstanding includes premium and associated intrinsic value associated with weather derivatives of $4 million at December 31, 2016 , $5 million at June 30, 2016, $10 million at December 31, 2015 , and $3 million at December 31, 2014 .

The net hedge volume of energy-related derivative contracts for natural gas positions for the years ended December 31 were as follows:

	Successor	Predecessor
	2016	2015
	mmBtu Volume	mmBtu Volume
	(in millions)	*(in millions)*
Commodity – Natural gas	**157**	(9)
Net Purchased/(Sold) Volume	**157**	(9)

The Company's derivative contracts are comprised of both long and short natural gas positions. A long position is a contract to purchase natural gas, and a short position is a contract to sell natural gas. The volume presented above represents the net of long natural gas positions of 3.31 billion mmBtu and short natural gas positions of 3.16 billion mmBtu at December 31, 2016 and the net of long natural gas positions of 3.09 billion mmBtu and short natural gas positions of 3.10 billion mmBtu at December 31, 2015 .

Energy-related derivative contracts that are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in cost of natural gas as the underlying gas is used in operations and ultimately recovered through the respective cost recovery clause. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges (which are mainly used to hedge anticipated purchases and sales), are initially deferred in OCI before being recognized in 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.

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 natural gas 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.

The Company uses OTC contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2 of the fair value hierarchy. See Note 9 to the financial statements for further discussion of fair value measurements.

The maturities of the energy-related derivative contracts at December 31, 2016 were as follows:

	Fair Value Measurements Successor – December 31, 2016			
		Maturity		
	Total Fair Value	Year 1	Years 2 & 3	Years 4 and thereafter
	(in millions)			
Level 1 [(a)]	$ (7)	$ 15	$ (15)	$ (7)
Level 2 [(b)]	19	11	—	8
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period [(c)]	$ 12	$ 26	$ (15)	$ 1

(a) Valued using NYMEX futures prices.

(b) Valued using basis transactions that represent the cost to transport natural gas from a NYMEX delivery point to the contract delivery point. These transactions are based on quotes obtained either through electronic trading platforms or directly from brokers.

(c) Excludes cash collateral of $62 million at December 31, 2016 .

Value at Risk (VaR)

VaR is the maximum potential loss in portfolio value over a specified time period that is not expected to be exceeded within a given degree of probability. The Company's VaR may not be comparable to that of other companies due to differences in the factors used to calculate VaR. The Company's VaR is determined on a 95% confidence interval and a one-day holding period, which means that 95% of the time, the risk of loss in a day from a portfolio of positions is expected to be less than or equal to the amount of VaR calculated. The open exposure of the Company is managed in accordance with established policies that limit market risk and require daily reporting of potential financial exposure to senior management. Because the Company generally manages physical gas assets and economically protects its positions by hedging in the futures markets, the Company's open exposure is generally mitigated. The Company employs daily risk testing, using both VaR and stress testing, to evaluate the risk of its positions.

The Company actively monitors open commodity positions and the resulting VaR and maintains a relatively small risk exposure as total buy volume is close to sell volume, with minimal open natural gas price risk. Based on a 95% confidence interval and employing a one-day holding period, SouthStar's portfolio of positions for the successor period of July 1, 2016 through December 31, 2016 and the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014 was immaterial.

For the periods presented below, wholesale gas services had the following VaRs:

	Successor	Predecessor		
	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30,	Years Ended December 31,	
	2016	2016	2015	2014
	(in millions)	(in millions)		
Period end	$ 2.3	$ 1.9	$ 2.4	$ 4.7
Average	2.0	2.0	3.0	4.3
High	2.8	2.5	7.3	19.7
Low	1.4	1.6	1.6	1.8

Credit Risk

Gas Distribution Operations

Atlanta Gas Light has a concentration of credit risk, as it bills 14 certificated and active Marketers in Georgia for its services. The credit risk exposure to Marketers varies seasonally, with the lowest exposure in the non-peak summer months and the highest exposure in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. The functions of the retail sale of gas include the purchase and sale of natural gas, customer service, billings, and collections. The

provisions of Atlanta Gas Light's tariff allow Atlanta Gas Light to obtain security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from Atlanta Gas Light. For 2016 , the four largest Marketers based on customer count accounted for 17% of the Company's consolidated adjusted operating margin and 20% of gas distribution operations' adjusted operating margin.

Several factors are designed to mitigate the Company's risks from the increased concentration of credit that has resulted from deregulation. In addition to the security support described above, Atlanta Gas Light bills intrastate delivery service to Marketers in advance rather than in arrears. Atlanta Gas Light accepts credit support in the form of cash deposits, letters of credit/surety bonds from acceptable issuers, and corporate guarantees from investment-grade entities. On a monthly basis, the Risk Management Committee reviews the adequacy of credit support coverage, credit rating profiles of credit support providers, and payment status of each Marketer. The Company believes that adequate policies and procedures are in place to properly quantify, manage, and report on Atlanta Gas Light's credit risk exposure to Marketers.

Atlanta Gas Light also faces potential credit risk in connection with assignments of interstate pipeline transportation and storage capacity to Marketers. Although Atlanta Gas Light assigns this capacity to Marketers, in the event that a Marketer fails to pay the interstate pipelines for the capacity, the interstate pipelines would likely seek repayment from Atlanta Gas Light.

Gas Marketing Services

The Company obtains credit scores for its firm residential and small commercial customers using a national credit reporting agency, enrolling only those customers that meet or exceed the Company's credit threshold. The Company considers potential interruptible and large commercial customers based on reviews of publicly available financial statements and commercially available credit reports. Prior to entering into a physical transaction, the Company also assigns physical wholesale counterparties an internal credit rating and credit limit based on the counterparties' Moody's, S&P, and Fitch ratings, commercially available credit reports, and audited financial statements.

Wholesale Gas Services

The Company has established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. The Company also utilizes master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When the Company is engaged in more than one outstanding derivative transaction with the same counterparty and also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of the Company's credit risk. The Company also uses other netting agreements with certain counterparties with whom it conducts significant transactions. Master netting agreements enable the Company to net certain assets and liabilities by counterparty. The Company also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions.

The Company may require counterparties to pledge additional collateral when deemed necessary. The Company conducts credit evaluations and obtains appropriate internal approvals for a counterparty's line of credit before any transaction with the counterparty is executed. In most cases, the counterparty must have an investment grade rating, which includes a minimum long-term debt rating of Baa3 from Moody's and BBB- from S&P. Generally, the Company requires credit enhancements by way of a guaranty, cash deposit, or letter of credit for transaction counterparties that do not have investment grade ratings.

Certain of the Company's derivative instruments contain credit-risk-related or other contingent features that could increase the payments for collateral it posts in the normal course of business when its financial instruments are in net liability positions. At December 31, 2016 , for agreements with such features, the Company's derivative instruments with liability fair values totaled $5 million , for which the Company had no collateral posted with derivatives counterparties to satisfy these arrangements.

The Company has a concentration of credit risk as measured by its 30-day receivable exposure plus forward exposure. At December 31, 2016 , wholesale gas services' top 20 counterparties represented approximately 46% , or $205 million , of its total counterparty exposure and had a weighted average S&P equivalent credit rating of A-, which is consistent with the prior year. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's, respectively, and 1 being D / Default by S&P and Moody's, respectively. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of that counterparty. To arrive at the weighted average credit rating, each counterparty is assigned an internal ratio, which is multiplied by their credit exposure and summed for all counterparties. The sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent.

The following table provides credit risk information related to the Company's third-party natural gas contracts receivable and payable positions at December 31:

	Gross Receivables		Gross Payables	
	Successor	Predecessor	**Successor**	Predecessor
	2016	2015	**2016**	2015
	(in millions)	*(in millions)*	*(in millions)*	*(in millions)*
Netting agreements in place:				
Counterparty is investment grade	**$ 375**	$ 299	**$ 227**	$ 136
Counterparty is non-investment grade	**14**	8	**31**	17
Counterparty has no external rating	**223**	133	**339**	265
No netting agreements in place:				
Counterparty is investment grade	**11**	5	**—**	—
Amount recorded in Consolidated Balance Sheets	**$ 623**	$ 445	**$ 597**	$ 418

Capital Requirements and Contractual Obligations

The Company's capital investments are currently estimated to total $1.7 billion for 2017 , $1.7 billion for 2018 , $1.7 billion for 2019 , $1.4 billion for 2020 , and $1.2 billion for 2021 . The regulatory infrastructure programs and other construction programs are subject to periodic review and revision, and actual costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in FERC rules and regulations; state regulatory agency approvals; changes in legislation; the cost and efficiency of labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to certain eligible employees and funds trusts to the extent required by the applicable state regulatory agencies.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, including the related interest; pipeline charges, storage capacity, and gas supply; operating leases; asset management agreements; standby letters of credit and performance/surety bonds; financial derivative obligations; pension and other postretirement benefit plans; and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 3, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

Contractual obligations at December 31, 2016 were as follows:

	2017	2018-2019	2020-2021	After 2021	Total
			(in millions)		
Long-term debt [a] —					
Principal	$ 22	$ 505	$ 330	$ 3,855	$ 4,712
Interest	207	406	364	2,500	3,477
Pipeline charges, storage capacity and gas supply [b]	822	1,049	746	2,591	5,208
Operating leases [c]	18	33	30	38	119
Asset management agreements [d]	10	7	—	—	17
Standby letters of credit and performance/surety bonds [e]	85	1	—	—	86
Financial derivative obligations [f]	487	70	11	1	569
Pension and other postretirement benefit plans [g]	21	45	—	—	66
Purchase commitments —					
Capital [h]	1,736	3,396	2,563	—	7,695
Other [i]	60	15	2	2	79
Total	$ 3,468	$ 5,527	$ 4,046	$ 8,987	$ 22,028

(a) 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 at January 1, 2017, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

(b) Includes charges recoverable through a natural gas cost recovery mechanism, or alternatively billed to Marketers, and demand charges associated with Sequent. The gas supply balance includes amounts for Nicor Gas and SouthStar gas commodity purchase commitments of 33 million mmBtu at floating gas prices calculated using forward natural gas prices at December 31, 2016 and valued at $106 million. As the Company does for certain of its affiliates, it provides guarantees to certain gas suppliers of SouthStar in support of payment obligations.

(c) Certain operating leases have provisions for step rent or escalation payments and certain lease concessions are accounted for by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms. However, this accounting treatment does not affect the future annual operating lease cash obligations as shown herein. The Company's operating leases are primarily for real estate.

(d) Represent fixed-fee minimum payments for Sequent's affiliated asset management agreements.

(e) Guarantees are provided to certain municipalities and other agencies and certain gas suppliers of SouthStar in support of payment obligations.

(f) Includes liabilities related to energy-related derivatives. For additional information, see Notes 1 and 10 to the financial statements.

(g) 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.

(h) Estimated capital expenditures are provided through 2021.

(i) Includes contractual environmental remediation liabilities that are generally recoverable through base rates or rate rider mechanisms and long-term service agreements.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2016 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning regulatory matters, the strategic goals for the Company, economic conditions, natural gas price volatility, derivative losses, regulatory 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 contributions, financing activities, completion dates of construction projects, filings with state and federal regulatory authorities, and estimated 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 also changes in tax and other laws and regulations to which the Company is subject, including potential tax reform legislation, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries ;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for natural gas, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of natural gas;
- limits on pipeline capacity;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities;
- investment performance of the Company's employee and retiree benefit plans ;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to natural gas and other cost recovery mechanisms;
- the inherent risks involved in transporting and storing natural gas;
- the ability to successfully operate the natural gas distribution and storage 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 possibility that the anticipated benefits from the Merger cannot be fully realized or may take longer to realize than expected, the possibility that costs related to integration with Southern Company will be greater than expected, the ability to retain and hire key personnel and maintain relationships with customers, suppliers, or other business partners, and the diversion of management time on integration related issues;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general ;
- 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. natural gas pipeline infrastructure or operation of storage resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

CONSOLIDATED STATEMENTS OF INCOME
Southern Company Gas and Subsidiary Companies 2016 Annual Report

	Successor	Predecessor		
	July 1, 2016 through December 31,	January 1, 2016 through June 30,	For the years ended December 31,	
	2016	2016	2015	2014
	(in millions)	*(in millions)*		
Operating Revenues:				
Natural gas revenues (includes revenue taxes of $32, $57, $103, and $133 for the periods presented, respectively)	$ 1,596	$ 1,841	$ 3,817	$ 5,257
Other revenues	56	64	124	128
Total operating revenues	1,652	1,905	3,941	5,385
Operating Expenses:				
Cost of natural gas	613	755	1,617	2,729
Cost of other sales	10	14	28	36
Other operations and maintenance	482	454	928	939
Depreciation and amortization	238	206	397	380
Taxes other than income taxes	71	99	181	208
Merger-related expenses	41	56	44	—
Total operating expenses	1,455	1,584	3,195	4,292
Gain on disposition of assets	—	—	—	2
Operating Income	197	321	746	1,095
Other Income and (Expense):				
Interest expense, net of amounts capitalized	(81)	(96)	(175)	(182)
Earnings from equity method investments	60	2	6	8
Other income (expense), net	14	5	9	9
Total other income and (expense)	(7)	(89)	(160)	(165)
Earnings Before Income Taxes	190	232	586	930
Income taxes	76	87	213	350
Income from continuing operations	114	145	373	580
Loss from discontinued operations, net of tax	—	—	—	80
Net Income	114	145	373	500
Less: Net income attributable to noncontrolling interest	—	14	20	18
Net Income Attributable to Southern Company Gas	$ 114	$ 131	$ 353	$ 482

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Southern Company Gas and Subsidiary Companies 2016 Annual Report

	Successor	Predecessor		
	July 1, 2016 through December 31,	**January 1, 2016 through June 30,**	For the years ended December 31,	
	2016	**2016**	2015	2014
	(in millions)	*(in millions)*		
Net Income	**$ 114**	**$ 145**	$ 373	$ 500
Other comprehensive income (loss):				
Qualifying hedges:				
Changes in fair value, net of tax of $(1), $(23), $(3), and $(2), respectively	**(1)**	**(41)**	—	(6)
Reclassification adjustment for amounts included in net income, net of tax of $-, $-, $1, and $(2), respectively	**—**	**1**	8	(3)
Pension and other postretirement benefit plans:				
Benefit plan net gain (loss), net of tax of $19, $-, $-, and $(48), respectively	**27**	**—**	—	(71)
Reclassification adjustment for amounts included in net income, net of tax of $-, $4, $9, and $5, respectively	**—**	**5**	12	8
Total other comprehensive income (loss)	**26**	**(35)**	20	(72)
Less: Comprehensive income attributable to noncontrolling interest	**—**	**14**	20	16
Comprehensive Income Attributable to Southern Company Gas	**$ 140**	**$ 96**	$ 373	$ 412

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
Southern Company Gas and Subsidiary Companies 2016 Annual Report

	Successor	Predecessor		
	July 1, 2016 through December 31,	January 1, 2016 through June 30,	For the years ended December 31,	
	2016	2016	2015	2014
	(in millions)	*(in millions)*		
Operating Activities:				
Net income	$ 114	$ 145	$ 373	$ 500
Adjustments to reconcile net income to net cash provided from (used for) operating activities —				
Depreciation and amortization, total	238	206	397	380
Deferred income taxes	92	8	211	199
Pension, postretirement, and other employee benefits	6	5	24	19
Pension and postretirement funding	(125)	—	—	—
Stock based compensation expense	20	20	34	19
Hedge settlements	(35)	(26)	—	—
Goodwill impairment	—	—	14	—
Mark-to-market adjustments	(3)	162	22	(155)
Loss on discontinued operations, net of tax	—	—	—	80
Other, net	(78)	(82)	43	(28)
Changes in certain current assets and liabilities —				
-Receivables	(490)	181	615	(53)
-Natural gas for sale	(226)	273	72	(58)
-Prepaid income taxes	(23)	151	23	(175)
-Other current assets	(31)	37	(11)	44
-Accounts payable	194	43	(434)	25
-Accrued taxes	8	41	(20)	(66)
-Accrued compensation	(13)	(21)	(6)	31
-Other current liabilities	24	(30)	24	(97)
Net cash used for operating activities of discontinued operations	—	—	—	(10)
Net cash provided from (used for) operating activities	(328)	1,113	1,381	655
Investing Activities:				
Property additions	(614)	(509)	(961)	(702)
Cost of removal, net of salvage	(40)	(32)	(84)	(39)
Change in construction payables, net	22	(7)	18	(28)
Investment in unconsolidated subsidiaries	(1,444)	(14)	(12)	(3)
Disposition of assets	—	—	—	230
Other investing activities	9	3	12	50
Net cash used for investing activities of discontinued operations	—	—	—	(13)
Net cash used for investing activities	(2,067)	(559)	(1,027)	(505)
Financing Activities:				
Increase (decrease) in notes payable, net	1,143	(896)	(165)	4
Proceeds —				
First mortgage bonds	—	250	—	—
Capital contributions from parent company	1,085	—	—	—
Senior notes	900	350	250	—
Redemptions and repurchases —				
First mortgage bonds	—	(125)	—	—
Senior notes	(420)	—	(200)	—
Distribution to noncontrolling interest	(15)	(19)	(18)	(17)
Purchase of 15% noncontrolling interest in SouthStar	(160)	—	—	—
Payment of common stock dividends	(126)	(128)	(244)	(233)

Other financing activities		**(8)**		**10**	11		22
Net cash provided from (used for) financing activities		**2,399**		**(558)**	(366)		(224)
Net Change in Cash and Cash Equivalents — Continuing Operations		**4**		**(4)**	(12)		(51)
Net Change in Cash and Cash Equivalents — Discontinued Operations		**—**		**—**	—		(23)
Cash and Cash Equivalents at Beginning of Period		**15**		**19**	31		105
Cash and Cash Equivalents at End of Period	**$**	**19**	**$**	**15** $	19	$	31

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED BALANCE SHEETS
Southern Company Gas and Subsidiary Companies 2016 Annual Report

	Successor	Predecessor
Assets	**December 31, 2016**	December 31, 2015
	(in millions)	*(in millions)*
Current Assets:		
Cash and cash equivalents	**$ 19**	$ 19
Receivables —		
Energy marketing receivable	**623**	445
Customer accounts receivable	**364**	316
Unbilled revenues	**239**	140
Other accounts and notes receivable	**76**	68
Accumulated provision for uncollectible accounts	**(27)**	(29)
Materials and supplies	**26**	29
Natural gas for sale	**631**	622
Prepaid income taxes	**24**	151
Prepaid expenses	**55**	67
Assets from risk management activities, net of collateral	**128**	206
Other regulatory assets, current	**81**	68
Other current assets	**11**	13
Total current assets	**2,250**	2,115
Property, Plant, and Equipment:		
In service	**14,508**	12,152
Less accumulated depreciation	**4,439**	2,775
Plant in service, net of depreciation	**10,069**	9,377
Construction work in progress	**496**	414
Total property, plant, and equipment	**10,565**	9,791
Other Property and Investments:		
Goodwill	**5,967**	1,813
Equity investments in unconsolidated subsidiaries	**1,541**	80
Other intangible assets, net of amortization of $34 and $68 at December 31, 2016 and December 31, 2015, respectively	**366**	109
Miscellaneous property and investments	**21**	23
Total other property and investments	**7,895**	2,025
Deferred Charges and Other Assets:		
Other regulatory assets, deferred	**973**	670
Other deferred charges and assets	**170**	153
Total deferred charges and other assets	**1,143**	823
Total Assets	**$ 21,853**	$ 14,754

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED BALANCE SHEETS
Southern Company Gas and Subsidiary Companies 2016 Annual Report

Liabilities and Stockholders' Equity	Successor December 31, 2016	Predecessor December 31, 2015
	(in millions)	*(in millions)*
Current Liabilities:		
Securities due within one year	**$ 22**	$ 545
Notes payable	**1,257**	1,010
Energy marketing trade payables	**597**	418
Accounts payable	**348**	255
Customer deposits	**153**	165
Accrued taxes —		
Accrued income taxes	**26**	13
Other accrued taxes	**68**	46
Accrued interest	**48**	49
Accrued compensation	**58**	92
Liabilities from risk management activities, net of collateral	**62**	44
Other regulatory liabilities, current	**102**	134
Accrued environmental remediation, current	**69**	67
Other current liabilities	**108**	162
Total current liabilities	**2,918**	3,000
Long-term Debt (See notes)	**5,259**	3,275
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**1,975**	1,912
Employee benefit obligations	**441**	515
Other cost of removal obligations	**1,616**	1,538
Accrued environmental remediation, deferred	**357**	364
Other regulatory liabilities, deferred	**51**	53
Other deferred credits and liabilities	**127**	122
Total deferred credits and other liabilities	**4,567**	4,504
Total Liabilities	**12,744**	10,779
Common Stockholders' Equity (See accompanying statements)	**9,109**	3,975
Total Liabilities and Stockholders' Equity	**$ 21,853**	$ 14,754
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
Southern Company Gas and Subsidiary Companies 2016 Annual Report

	Southern Company Gas Common Stockholders' Equity								
	Number of Common Shares		Common Stock						
	Issued	Treasury	Par Value	Paid-In Capital	Treasury	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	(in thousands)		*(in millions)*						
Predecessor – Balance at December 31, 2013	118,889	217	$ 595	$ 2,054	$ (8)	$ 1,063	$ (136)	$ 45	$ 3,613
Consolidated net income attributable to Southern Company Gas	—	—	—	—	—	482	—	—	482
Other comprehensive income (loss)	—	—	—	—	—	—	(70)	(2)	(72)
Stock issued	236	—	1	11	—	—	—	—	12
Stock-based compensation	522	—	3	22	—	—	—	—	25
Cash dividends on common stock	—	—	—	—	—	(233)	—	—	(233)
Distribution to noncontrolling interest (*)	—	—	—	—	—	—	—	(17)	(17)
Net income attributable to noncontrolling interest (*)	—	—	—	—	—	—	—	18	18
Predecessor – Balance at December 31, 2014	119,647	217	599	2,087	(8)	1,312	(206)	44	3,828
Consolidated net income attributable to Southern Company Gas	—	—	—	—	—	353	—	—	353
Other comprehensive income	—	—	—	—	—	—	20	—	20
Stock issued	221	—	1	11	—	—	—	—	12
Stock-based compensation	509	—	3	1	—	—	—	—	4
Cash dividends on common stock	—	—	—	—	—	(244)	—	—	(244)
Distribution to noncontrolling interest (*)	—	—	—	—	—	—	—	(18)	(18)
Net income attributable to noncontrolling interest (*)	—	—	—	—	—	—	—	20	20
Predecessor – Balance at December 31, 2015	**120,377**	**217**	**603**	**2,099**	**(8)**	**1,421**	**(186)**	**46**	**3,975**
Consolidated net income attributable to Southern Company Gas	**—**	**—**	**—**	**—**	**—**	**131**	**—**	**—**	**131**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**—**	**—**	**(35)**	**—**	**(35)**
Stock issued	**95**	**—**	**—**	**6**	**—**	**—**	**—**	**—**	**6**
Stock-based compensation	**270**	**—**	**2**	**28**	**—**	**—**	**—**	**—**	**30**
Cash dividends on common stock	**—**	**—**	**—**	**—**	**—**	**(128)**	**—**	**—**	**(128)**
Reclassification of noncontrolling interest (*)	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(46)**	**(46)**
Predecessor – Balance at June 30, 2016	**120,742**	**217**	**$ 605**	**$ 2,133**	**$ (8)**	**$ 1,424**	**$ (221)**	**$ —**	**$ 3,933**
Successor – Balance at July 1, 2016	**—**	**—**	**—**	**8,001**	**—**	**—**	**—**	**—**	**8,001**
Consolidated net income attributable to Southern Company Gas	**—**	**—**	**—**	**—**	**—**	**114**	**—**	**—**	**114**
Capital contributions from parent company	**—**	**—**	**—**	**1,085**	**—**	**—**	**—**	**—**	**1,085**
Other comprehensive income	**—**	**—**		**—**	**—**	**—**	**26**	**—**	**26**
Stock-based compensation	**—**	**—**	**—**	**9**	**—**	**—**	**—**	**—**	**9**
Cash dividends on common stock	**—**	**—**	**—**	**—**	**—**	**(126)**	**—**	**—**	**(126)**
Successor – Balance at December 31, 2016	**—**	**—**	**$ —**	**$ 9,095**	**$ —**	**$ (12)**	**$ 26**	**$ —**	**$ 9,109**

(*) Associated with SouthStar. See Note 4 to the financial statements for additional information.

The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO FINANCIAL STATEMENTS
Southern Company Gas and Subsidiary Companies 2016 Annual Report

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1 . SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

On July 1, 2016, Southern Company and Southern Company Gas (formerly known as AGL Resources Inc.) (together with its subsidiaries, the Company) completed the Merger and Southern Company Gas became a wholly-owned, direct subsidiary of Southern Company and, on July 11, 2016, changed its name to Southern Company Gas. In addition to the Company, Southern Company is the parent company of four traditional electric operating companies, Southern Power, Southern Company Services, Inc. (SCS), Southern LINC, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure, Inc., and other direct and indirect subsidiaries. Southern Company Gas is an energy services holding company whose primary business is the distribution of natural gas across seven states through its seven natural gas distribution utilities. The Company also is involved in several other businesses that are complementary to the distribution of natural gas. The traditional electric operating companies – Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern LINC provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and for other electric services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants. PowerSecure, Inc. is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.

The financial statements reflect the Company's investments in its subsidiaries on a consolidated basis. The equity method is used for subsidiaries in which the Company has significant influence but does not control and for VIEs where the Company has an equity investment, but is not the primary beneficiary. Intercompany transactions have been eliminated in consolidation.

The seven natural gas distribution utilities are subject to regulation by the regulatory agencies of each state in which they operate. 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.

Pursuant to the Merger, Southern Company has pushed down the application of the acquisition method of accounting to the consolidated financial statements of the Company such that the assets and liabilities are recorded at their respective fair values, and goodwill has been established for the excess of the purchase price over the fair value of net identifiable assets. Accordingly, the consolidated financial statements of the Company for periods before and after July 1, 2016 (acquisition date) reflect different bases of accounting, and the financial positions and results of operations of those periods are not comparable. Throughout the consolidated financial statements and notes to the financial statements, periods prior to July 1, 2016 are identified as "predecessor," while periods after the acquisition date are identified as "successor."

Certain predecessor period data presented in the financial statements has been modified or reclassified to conform to the presentation used by the Company's new parent company, Southern Company. Changes to the consolidated statements of income include classifying operating revenues as natural gas revenues and other revenues as well as classifying cost of goods sold as cost of natural gas and cost of other sales, and presenting interest expense and AFUDC on a gross basis. Changes to the consolidated statements of cash flows include revised financial statement line item descriptions to align with the new balance sheet descriptions and expanded line items within each category of cash flow activity. Changes to the consolidated balance sheets include changing certain captions to conform to the presentation of Southern Company.

Recently Issued Accounting Standards

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers,* replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

While the Company expects most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of such arrangements. The majority of the Company's revenue, including energy provided to customers, is from tariff offerings that provide natural gas without a defined contractual term. For such arrangements, the Company generally expects that the revenue from contracts with these customers will continue to be equivalent to the natural gas supplied and billed in that period

(including unbilled revenues) and the adoption of ASC 606 will not result in a significant shift in the timing of revenue recognition for such sales.

The Company's ongoing evaluation of other revenue streams and related contracts includes longer term contractual commitments and unregulated sales to customers. Some revenue arrangements, such as certain alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on the Company's financial statements. In addition, the power and utilities industry is currently addressing other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). If final implementation guidance indicates CIAC will be accounted for under ASC 606 and offsetting regulatory treatment is not permitted, it could have a material impact on the Company's financial statements.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. The Company must select a transition method to be applied either retrospectively to each prior reporting period presented or retrospectively with a cumulative effect adjustment to retained earnings at the date of initial adoption. As the ultimate impact of the new standard has not yet been determined, the Company has not elected its transition method.

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, the Company elected to early adopt the guidance in 2016. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of the Company.

On February 25, 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged and there is no change to the accounting for existing leveraged leases. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company is currently evaluating the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

On March 30, 2016, the FASB issued ASU No. 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Note 5 for the disclosure impacted by ASU 2016-09.

On October 24, 2016, the FASB issued ASU No. 2016-16, *Income Taxes (Topic 740), Intra-Entity Transfers of Assets Other Than Inventory* (ASU 2016-16). Current GAAP prohibits the recognition of current and deferred income taxes for an affiliate asset transfer until the asset has been sold to an outside party. ASU 2016-16 requires an entity to recognize the income tax consequences of an affiliate transfer of an asset other than inventory when the transfer occurs. ASU 2016-16 is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. The amendments will be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The Company is currently assessing the impact of the standard on its financial statements.

On November 17, 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* (ASU 2016-18). ASU 2016-18 eliminates the need to reflect transfers between cash and restricted cash in operating, investing, and financing activities in the statement of cash flows. Upon adoption, the net change in cash and cash equivalents during the period will include amounts generally described as restricted cash or restricted cash equivalents. ASU 2016-18 is effective for fiscal years beginning after December 15, 2017, with early adoption permitted, and will be applied retrospectively to each period presented. The Company does not intend to adopt the guidance early. The adoption of ASU 2016-18 will not have a material impact on the financial statements of the Company.

Affiliate Transactions

Prior to the Company's completion of its acquisition of a 50% equity interest in SNG, the Company entered into a long-term interstate natural gas transportation agreement with SNG. The interstate transportation service provided to the Company by SNG pursuant to this agreement is governed by the terms and conditions of SNG's natural gas tariff and is subject to FERC regulation. For the period subsequent to the Company's investment in SNG, transportation costs paid to SNG by the Company were approximately $15 million . See Note 4 herein under "Equity Method Investments – SNG" for additional information regarding the Company's investment in SNG.

The Company has an agreement with SCS under which the following services are currently being rendered to the Company as direct or allocated cost: accounting, finance and treasury, tax, information technology, auditing, insurance and pension administration, human resources, systems and procedures, purchasing, and other services. For the successor period of July 1, 2016 through December 31, 2016 , costs for these services amounted to $17 million .

SouthStar and Sequent each have agreements under which they sell natural gas to SCS, as agent for the traditional electric operating companies and Southern Power. For the successor period of July 1, 2016 through December 31, 2016 , revenue from these agreements totaled $9 million and $19 million , respectively.

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:

	Successor	Predecessor	
	2016	2015	Note
	(in millions)	*(in millions)*	
Deferred income tax credits	**$ (22)**	$ (27)	(a)
Long-term debt fair value adjustment	**154**	66	(b)
Environmental remediation - asset	**411**	401	(h)
Under recovered regulatory clause revenues	**118**	69	(c)
Financial instrument hedging - asset	**—**	30	(d,h)
Other regulatory assets	**58**	47	(e)
Other cost of removal obligations	**(1,616)**	(1,591)	(a)
Financial instrument hedging - liability	**(21)**	—	(d,h)
Other regulatory liabilities	**(18)**	(20)	(f)
Retiree benefit plans	**325**	125	(g,h)
Over recovered regulatory clause revenues	**(104)**	(87)	(c)
Total regulatory assets (liabilities), net	**$ (715)**	$ (987)	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Deferred income tax assets and liabilities are amortized over the related property lives, which range up to 30 years .

(b) Recovered over the remaining life of the original debt issuances, which range up to 22 years .

(c) Recorded and recovered or amortized as approved or accepted by the applicable state regulatory agencies over periods not exceeding nine years .

(d) Financial instrument-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed two years . Upon final settlement, actual costs incurred are recovered, and actual income earned is refunded through the energy cost recovery clause.

(e) Comprised of several components including unamortized loss on reacquired debt, weather normalization, franchise gas, and deferred depreciation expense, which are recovered or amortized as approved by the applicable state regulatory agencies over periods generally not exceeding ten years .

(f) Comprised of several components including energy efficiency programs and unamortized bond issuance costs which are recovered or amortized as approved by the applicable state regulatory agencies over periods generally not exceeding four years .

(g) Recovered and amortized over the average remaining service period which range up to 11 years . See Note 2 for additional information.

(h) Not earning a return as offset in rate base by a corresponding asset or liability.

In the event that a portion of its operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income 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 "Regulatory Matters" for additional information.

Revenues

Gas Distribution Operations

The Company records revenues when goods or services are provided to customers. Those revenues are based on rates approved by the state regulatory agencies of the Company's utilities. As required by the Georgia PSC, Atlanta Gas Light bills Marketers in equal monthly installments for each residential, commercial, and industrial end-use customer's distribution costs as well as for capacity costs utilizing a seasonal rate design for the calculation of each residential end-use customer's annual straight-fixed-variable charge, which reflects the historic volumetric usage pattern for the entire residential class.

All of the natural gas utilities, with the exception of Atlanta Gas Light, have rate structures that include volumetric rate designs that allow the opportunity to recover certain costs based on gas usage. Revenues from sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Revenues from residential and certain commercial and industrial customers are recognized on the basis of scheduled meter readings. Additionally, unbilled revenues are recognized for estimated deliveries of gas not yet billed to these customers, from the last bill date to the end of the accounting period. For other commercial and industrial customers and for all wholesale customers, revenues are based on actual deliveries to the end of the period.

The tariffs for Virginia Natural Gas, Elizabethtown Gas, and Chattanooga Gas contain weather normalization adjustments (WNAs) that partially mitigate the impact of unusually cold or warm weather on customer billings and natural gas revenues. The WNAs have the effect of reducing customer bills when winter weather is colder than normal and increasing customer bills when weather is warmer than normal. In addition, the tariffs for Virginia Natural Gas, Chattanooga Gas, and Elkton Gas contain revenue normalization mechanisms that mitigate the impact of conservation and declining customer usage. The WNAs and revenue normalization mechanisms are alternative revenue programs, which allow recognition of revenue prior to billing as long as the amounts will be collected within 24 months of recognition.

Revenue Taxes

The Company charges customers for gas revenue and gas use taxes imposed on the Company and remits amounts owed to various governmental authorities. Gas revenue taxes are recorded at the amount charged to customers, which may include a small administrative fee, as operating revenues, and the related taxes imposed on the Company are recorded as operating expenses on the statements of income. Gas use taxes are excluded from revenue and expense with the related administrative fee included in operating revenues when the tax is imposed on the customer. Revenue taxes included in operating expenses were $31 million for the successor period of July 1, 2016 through December 31, 2016 and $56 million , $101 million , and $130 million for the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014 , respectively.

Gas Marketing Services

The Company recognizes revenues from natural gas sales and transportation services in the same period in which the related volumes are delivered to customers and recognizes sales revenues from residential and certain commercial and industrial customers on the basis of scheduled meter readings. The Company also recognizes unbilled revenues for estimated deliveries of gas not yet billed to these customers from the most recent meter reading date to the end of the accounting period. For other commercial and industrial customers and for all wholesale customers, revenues are based on actual deliveries during the period.

The Company recognizes revenues on 12-month utility-bill management contracts as the lesser of cumulative earned or cumulative billed amounts. Revenues for warranty and repair contracts are recognized on a straight-line basis over the contract term while revenues for maintenance services are recognized at the time such services are performed.

Wholesale Gas Services

The Company nets revenues from energy and risk management activities with the associated costs. Profits from sales between segments are eliminated and are recognized as goods or services sold to end-use customers. The Company records transactions that qualify as derivatives at fair value with changes in fair value recognized in earnings in the period of change and characterized as unrealized gains or losses. Gains and losses on derivatives held for energy trading purposes are presented on a net basis in revenue.

Concentration of Revenue

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.

Cost of Natural Gas and Other Sales

Gas Distribution Operations

Excluding Atlanta Gas Light, which does not sell natural gas to end-use customers, the Company charges its utility customers for natural gas consumed using natural gas cost recovery mechanisms set by the applicable state regulatory agencies. Under these mechanisms, all prudently incurred natural gas costs are passed through to customers without markup, subject to regulatory review. The Company defers or accrues the difference between the actual cost of natural gas and the amount of commodity revenue earned in a given period such that no operating income is recognized related to these costs. The deferred or accrued amount is either billed or refunded to customers prospectively through adjustments to the commodity rate. Deferred and accrued natural gas costs are included in the consolidated balance sheets as regulatory assets and regulatory liabilities, respectively.

Gas Marketing Services

The Company's gas marketing services' customers are charged for actual or estimated natural gas consumed. Within cost of natural gas, the Company also includes costs of fuel and lost and unaccounted for gas, adjustments to reduce the value of inventories to market value, and gains and losses associated with certain derivatives. The Company records the costs to service its warranty and repair contract claims as cost of other sales.

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 on the balance sheet, excluding revenue taxes which are presented on the statements of income. See "Revenues – Gas Distribution Operations – Revenue Taxes" herein for additional information.

The Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost, or fair value at the effective date of the Merger as appropriate, 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:

	Successor	Predecessor
	2016	2015
	(in millions)	*(in millions)*
Utility plant in service	**$ 11,996**	$ 9,912
Information technology equipment and software	**324**	415
Storage facilities	**1,463**	1,255
Other	**725**	570
Total other plant in service	**2,512**	2,240
Total plant in service	**$ 14,508**	$ 12,152

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. The portion of pad gas at the Company's natural gas storage facilities considered to be non-recoverable is recorded as depreciable property, plant, and equipment, while the recoverable or retained portion is recorded as non-depreciable property, plant, and equipment.

The amount of non-cash property additions recognized for the successor period of July 1, 2016 through December 31, 2016 and the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014 was $63 million , $41 million , $48 million , and $31 million , respectively. These amounts are comprised of construction-related accounts payable outstanding at the end of each period.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided using composite straight-line rates, which approximated 2.8% in 2016 and 2.7% in each of 2015 and 2014. Depreciation studies are conducted periodically to update the composite rates that are approved by the respective state regulatory agency. 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 asset are retired when the related property unit is retired.

Depreciation of the original cost of other plant in service is provided primarily on a straight-line basis over the following useful lives: five to 15 years for transportation equipment, 40 to 60 years for storage facilities, and up to 65 years for other assets.

Allowance for Funds Used During Construction

The Company records AFUDC for Atlanta Gas Light, Nicor Gas, Chattanooga Gas, and Elizabethtown Gas, 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 asset through a higher rate base and higher depreciation. All current construction costs are included in rates. The capital expenditures of the other three natural gas utilities do not qualify for AFUDC treatment.

The Company's AFUDC composite rates are as follows:

	Successor	Predecessor		
	July 1, 2016 through December 31,	**January 1, 2016 through June 30,**	Years ended December 31,	
	2016	**2016**	2015	2014
Atlanta Gas Light	**4.05%**	**4.05%**	8.10%	8.10%
Chattanooga Gas [(*)]	**3.71**	**3.71**	7.41	7.41
Elizabethtown Gas [(*)]	**0.84**	**0.84**	1.69	0.44
Nicor Gas [(*)]	**1.50**	**1.50**	0.82	0.24

(*) Variable rate is determined by the FERC method of AFUDC accounting.

Cash payments for interest during the successor period of July 1, 2016 through December 31, 2016 and the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014 totaled $135 million , $119 million , $181 million , and $187 million , respectively.

Goodwill and Other Intangible Assets and Liabilities

Goodwill is not amortized, but is subject to an annual impairment test during the fourth quarter of each year, or more frequently if impairment indicators arise. In assessing goodwill for impairment, the Company has the option of first performing a qualitative assessment to determine that it is more likely than not that fair value of its reporting unit exceeds its carrying value (commonly referred to as Step 0). If the Company chooses not to perform a qualitative assessment, or the result of Step 0 indicates a probable decrease in fair value of its reporting unit below its carrying value, a quantitative two-step test is performed (commonly referred to as Step 1 and Step 2). Step 1 compares the fair value of the reporting unit to its carrying value including goodwill. If the carrying value exceeds the fair value, Step 2 is performed to allocate the fair value of the reporting unit to its assets and liabilities in order to determine the implied fair value of goodwill, which is compared to the carrying value of goodwill to calculate an impairment loss, if any.

The Company performed Step 1 of the impairment test in the fourth quarter 2014, which resulted in the fair values of all reporting units with goodwill exceeding their respective carrying value. However, the Company noted that the fair value of the storage and fuels reporting unit, which had $14 million of goodwill, exceeded its carrying value by less than 5% and would be at risk of failing Step 1 of the test if a further decline in fair value were to occur. While preparing the third quarter 2015 financial statements, and in connection with the 2016 annual budget process, the Company concluded that a decline in projected storage

subscription rates as well as a reduction in the near-term projection of the reporting unit's profitability required an interim goodwill impairment test to be performed as of September 30, 2015.

The Company performed Step 1 and Step 2 for the interim goodwill impairment test. Based on this assessment, a non-cash impairment charge for the entire $14 million of goodwill was recorded as of September 30, 2015.

For the 2016 and 2015 annual goodwill impairment tests, the Step 0 assessment was performed focusing on the following qualitative factors: macroeconomic conditions, industry and market conditions, cost factors, financial performance, entity specific events, and events specific to each reporting unit. This Step 0 analysis concluded that it is more likely than not that the fair value of the Company's reporting units that have goodwill exceeds their carrying amounts and a quantitative assessment was not required.

Goodwill and other intangible assets consisted of the following:

		Successor - At December 31, 2016		
	Estimated Useful Life	Gross Carrying Amount	Accumulated Amortization	Other Intangible Assets, Net
			(in millions)	
Other intangible assets subject to amortization:				
Gas marketing services				
Customer relationships	11-14 years	$ 221	$ (30)	$ 191
Trade names	10-28 years	115	(2)	113
Wholesale gas services				
Storage and transportation contracts	1-5 years	64	(2)	62
Total intangible assets subject to amortization		$ 400	$ (34)	$ 366
Goodwill:				
Gas distribution operations (*)		$ 4,702	$ —	4,702
Gas marketing services		1,265	—	1,265
Total goodwill		$ 5,967	$ —	$ 5,967

(*) Measurement period adjustments were recorded in acquisition accounting during the fourth quarter 2016 that resulted in a net $30 million increase to goodwill.

		Predecessor - At December 31, 2015		
	Estimated Useful Life	Gross Carrying Amount	Accumulated Amortization	Other Intangible Assets, Net
			(in millions)	
Other intangible assets subject to amortization:				
Gas marketing services				
Customer relationships	11-14 years	$ 132	$ (57)	$ 75
Trade names	10-28 years	45	(11)	34
Total intangible assets subject to amortization		$ 177	$ (68)	$ 109
Goodwill:				
Gas distribution operations		$ 1,640	$ —	$ 1,640
Gas marketing services		173	—	173
Total goodwill		$ 1,813	$ —	$ 1,813

Amortization associated with intangible assets during the successor period of July 1, 2016 through December 31, 2016 and the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014 was $32 million , $8 million , $18 million , and $20 million , respectively. Amortization of $2 million for wholesale gas services is recorded as a reduction to operating revenues. The increases in goodwill and other intangible assets relate to purchase accounting adjustments associated with the Merger. See Note 11 under "Merger with Southern Company" for additional information.

As of December 31, 2016 , the estimated amortization associated with other intangible assets is as follows:

	Amortization
	(in millions)
2017	$ 73
2018	58
2019	40
2020	28
2021	21

Included in other deferred credits and liabilities on the balance sheets is $91 million of intangible liabilities that were recorded during acquisition accounting for transportation contracts at wholesale gas services. At December 31, 2016 , the accumulated amortization of these intangible liabilities was $21 million . The estimated amortization associated with the intangible liabilities that will be recorded in natural gas revenues is as follows:

	Amortization
	(in millions)
2017	$ 29
2018	24
2019	17

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.

Energy Marketing Receivables and Payables

Wholesale gas services provides services to retail gas marketers, wholesale gas marketers, utility companies, and industrial customers. These counterparties utilize netting agreements that enable wholesale gas services to net receivables and payables by counterparty upon settlement. Wholesale gas services also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions. While the amounts due from, or owed to, wholesale gas services' counterparties are settled net, they are recorded on a gross basis in the consolidated balance sheets as energy marketing receivables and energy marketing payables.

Wholesale gas services has trade and credit contracts that contain minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if the Company's credit ratings are downgraded to non-investment grade status. Under such circumstances, wholesale gas services would need to post collateral to continue transacting business with some of its counterparties. As of December 31, 2016 and 2015 , the required collateral in the event of a credit rating downgrade was immaterial.

Wholesale gas services has a concentration of credit risk for services it provides to its counterparties. This credit risk is generally concentrated in 20 of its counterparties and is measured by 30-day receivable exposure plus forward exposure. Counterparty credit risk is evaluated using an S&P equivalent credit rating, which is determined by a process of converting the lower of the S&P or Moody's rating to an internal rating ranging from 9 to 1 , with 9 being equivalent to AAA/Aaa by S&P and Moody's, respectively, and 1 being equivalent to D/Default by S&P and Moody's, respectively. A counterparty that does not have an external rating is assigned an internal rating based on the strength of its financial ratios. As of December 31, 2016 , the top 20 counterparties represented 46% , or $205 million , of the total counterparty exposure and had a weighted average S&P equivalent rating of A-.

Credit policies were established to determine and monitor the creditworthiness of counterparties, including requirements to post collateral or other credit security, as well as the quality of pledged collateral. Collateral or credit security is most often in the form of cash or letters of credit from an investment-grade financial institution, but may also include cash or U.S. government securities held by a trustee. When wholesale gas services is engaged in more than one outstanding derivative transaction with the same counterparty and it also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty combined with a reasonable measure of the Company's credit risk. Wholesale gas services also uses other netting agreements with certain counterparties with whom it conducts significant transactions.

Receivables and Allowance for Uncollectible Accounts

The Company's other trade receivables consist primarily of natural gas sales and transportation services billed to residential, commercial, industrial, and other customers. Customers are billed monthly and payment is due within 30 days. For the majority of receivables, an allowance for doubtful accounts is established based on historical collection experience and other factors. For the remaining receivables, if the Company is aware of a specific customer's inability to pay, an allowance for doubtful accounts is recorded to reduce the receivable balance to the amount the Company reasonably expects to collect. If circumstances change, the estimate of the recoverability of accounts receivable could change as well. Circumstances that could affect this estimate include, but are not limited to, customer credit issues, customer deposits, and general economic conditions. Customers' accounts are written off once they are deemed to be uncollectible.

Nicor Gas

Credit risk exposure at Nicor Gas is mitigated by a bad debt rider approved by the Illinois Commission. The bad debt rider provides for the recovery from (or refund to) customers of the difference between Nicor Gas' actual bad debt experience on an annual basis and the benchmark bad debt expense used to establish its base rates for the respective year.

Atlanta Gas Light

Concentration of credit risk occurs at Atlanta Gas Light for amounts billed for services and other costs to its customers, which consist of 14 Marketers in Georgia. The credit risk exposure to Marketers varies seasonally, with the lowest exposure in the non-peak summer months and the highest exposure in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. The functions of the retail sale of gas include the purchase and sale of natural gas, customer service, billings, and collections. Atlanta Gas Light obtains credit security support in an amount equal to no less than two times a Marketer's highest month's estimated bill from Atlanta Gas Light.

Materials and Supplies

Generally, materials and supplies include propane gas inventory, fleet fuel, and other materials and supplies. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Natural Gas for Sale

The natural gas distribution utilities, with the exception of Nicor Gas, record natural gas inventories on a WACOG basis. In Georgia's competitive environment, Marketers sell natural gas to firm end-use customers at market-based prices. Part of the unbundling process, which resulted from deregulation and provides this competitive environment, is the assignment to Marketers of certain pipeline services that Atlanta Gas Light has under contract. On a monthly basis, Atlanta Gas Light assigns to Marketers the majority of the pipeline storage services that it has under contract, along with a corresponding amount of inventory. Atlanta Gas Light retains and manages a portion of its pipeline storage assets and related natural gas inventories for system balancing and to serve system demand.

Nicor Gas' inventory is carried at cost on a LIFO basis. Inventory decrements occurring during the year that are restored prior to year end are charged to cost of natural gas at the estimated annual replacement cost. Inventory decrements that are not restored prior to year end are charged to cost of natural gas at the actual LIFO cost of the inventory layers liquidated. The cost of gas, including inventory costs, is recovered from customers under a purchased gas recovery mechanism adjusted for differences between actual costs and amounts billed; therefore, LIFO liquidations have no impact on the Company's net income. At December 31, 2016 , the Nicor Gas LIFO inventory balance was $148 million . Based on the average cost of gas purchased in December 2016, the estimated replacement cost of Nicor Gas' inventory at December 31, 2016 was $310 million , which exceeded the LIFO cost by $162 million . During 2016 , Nicor Gas did not liquidate any LIFO-based inventory.

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The gas marketing services, wholesale gas services, and all other segments record inventory at LOCOM, with cost determined on a WACOG basis. For these segments, the Company evaluates the weighted average cost of its natural gas inventories against market prices to determine whether any declines in market prices below the WACOG are other than temporary. As indicated in the following table, for any declines considered to be other than temporary, the Company recorded LOCOM adjustments to cost of natural gas to reduce the value of its natural gas inventories to market value.

	Successor	Predecessor		
	July 1, 2016 to December 31, 2016	January 1, 2016 to June 30, 2016	2015	2014
	(in millions)	(in millions)		
Gas marketing services	$ —	$ —	$ 3	$ 4
Wholesale gas services	1	3	19	73
All other	—	—	1	—
Total	$ 1	$ 3	$ 23	$ 77

Fair Value Measurements

The Company has financial and nonfinancial assets and liabilities subject to fair value measurement. The financial assets and liabilities measured and carried at fair value include cash and cash equivalents and derivative instruments. The carrying values of receivables, short and long-term investments, accounts payable, short-term debt, other current assets and liabilities, and accrued interest approximate their respective fair value. The nonfinancial assets and liabilities include pension and welfare benefits. See Notes 2 and 9 for additional fair value disclosures.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company utilizes market data or assumptions that market participants would use in valuing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company primarily applies the market approach for recurring fair value measurements to utilize the best available information. Accordingly, the Company uses valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. Fair value balances are classified based on the observance of those inputs. The guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy defined by the guidance are as follows:

Level 1

Quoted prices in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. The Company's Level 1 items consist of exchange-traded derivatives, money market funds, and certain retirement plan assets.

Level 2

Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial and commodity instruments that are valued using valuation methodologies. These methodologies are primarily industry-standard methodologies that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. Market price data is obtained from multiple sources in order to value certain Level 2 transactions and this data is representative of transactions that occurred in the marketplace. Level 2 instruments include shorter tenor exchange-traded and non-exchange-traded derivatives such as over-the-counter (OTC) forwards and options and certain retirement plan assets.

Level 3

Pricing inputs include significant unobservable inputs that may be used with internally developed methodologies to determine management's best estimate of fair value from the perspective of market participants. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs. Level 3 assets, liabilities, and any applicable transfers are primarily

related to the Company's pension and welfare benefit plan assets as described in Note 2. Transfers into and out of Level 3 are determined using values at the end of the interim period in which the transfer occurred.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in natural gas prices, weather, interest rates, and commodity prices. All derivative financial instruments are recognized as either assets or liabilities on the balance sheets (shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information regarding fair value. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the respective state regulatory agency approved fuel-hedging programs result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. See Note 10 for additional information regarding derivatives.

The Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. The Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2016 .

The Company enters into weather derivative contracts as economic hedges of natural gas revenues in the event of warmer-than-normal weather in the Heating Season. Exchange-traded options are carried at fair value, with changes reflected in natural gas revenues. Non-exchange-traded options are accounted for using the intrinsic value method. Changes in the intrinsic value for non-exchange-traded contracts are also reflected in natural gas revenues in the consolidated statements of income.

Wholesale gas services purchases natural gas for storage when the current market price paid to buy and transport natural gas plus the cost to store and finance the natural gas is less than the market price that can be received in the future, resulting in positive net natural gas revenues. NYMEX futures and OTC contracts are used to sell natural gas at that future price to substantially protect the natural gas revenues that will ultimately be realized when the stored natural gas is sold. The Company enters into transactions to secure transportation capacity between delivery points in order to serve its customers and various markets. NYMEX futures and OTC contracts are used to capture the price differential or spread between the locations served by the capacity in order to substantially protect the natural gas revenues that will ultimately be realized when the physical flow of natural gas between delivery points occurs. These contracts generally meet the definition of derivatives and are carried at fair value on the consolidated balance sheets, with changes in fair value recorded in natural gas revenues on the consolidated statements of income in the period of change. These contracts are not designated as hedges for accounting purposes.

The purchase, transportation, storage, and sale of natural gas are accounted for on a weighted average cost or accrual basis, as appropriate, rather than on the fair value basis utilized for the derivatives used to mitigate the natural gas price risk associated with the storage and transportation portfolio. Monthly demand charges are incurred for the contracted storage and transportation capacity and payments associated with asset management agreements, and these demand charges and payments are recognized on the consolidated statements of income in the period they are incurred. This difference in accounting methods can result in volatility in reported earnings, even though the economic margin is substantially unchanged from the dates the transactions were consummated.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, certain changes in pension and other postretirement benefit plans, and reclassifications for amounts included in net income.

Non-Wholly Owned Entities

The Company holds ownership interests in a number of business ventures with varying ownership structures and evaluates all of its partnership interests and other variable interests to determine if each entity is a VIE. If a venture is a VIE for which the Company is the primary beneficiary, the assets, liabilities, and results of operations of the entity are consolidated. The Company reassesses its conclusion as to whether an entity is a VIE upon certain occurrences, which are deemed reconsideration events under the guidance. See Note 4 under "Variable Interest Entities" for additional information.

For entities that are not determined to be VIEs, the Company evaluates whether it has control or significant influence over the investee to determine the appropriate consolidation and presentation. Generally, entities under the control of the Company are consolidated, and entities over which the Company can exert significant influence, but does not control, are accounted for under the equity method of accounting. However, the Company also invests in partnerships and limited liability companies that maintain separate ownership accounts. All such investments are required to be accounted for under the equity method unless the interest is so minor that there is virtually no influence over operating and financial policies, as are all investments in joint ventures.

Investments accounted for under the equity method are recorded within equity investments in unconsolidated subsidiaries within the other property and investments section in the consolidated balance sheets and the equity income is recorded within earnings from equity method investments within the other income (expense) section in the consolidated statements of income. See Note 4 under "Equity Method Investments" for additional information.

Earnings per Share

Upon consummation of the Merger, all of Southern Company Gas' shares are held by Southern Company. As a result, earnings per common share disclosures are no longer required.

2 . RETIREMENT BENEFITS

Effective July 1, 2016, in connection with the Merger, SCS became the sponsor of the Company's pension and other post-retirement benefit plans.

The Company has a qualified defined benefit, trusteed, pension plan – AGL Resources Inc. Retirement Plan – covering certain eligible employees, which was closed in 2012 to new employees. The qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). On September 12, 2016, the Company voluntarily contributed $125 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2017. The Company also provides certain non-qualified defined benefit and defined contribution 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 eligible retired employees through a postretirement benefit plan – AGL Welfare Plan. The Company also has a separate unfunded supplemental retirement health care plan that provides medical care and life insurance benefits to employees of discontinued businesses. For the year ending December 31, 2017 , no other postretirement trust contributions are expected.

In connection with the Merger, the Company performed updated valuations of its pension and other postretirement benefit plan assets and obligations to reflect actual census data at the new measurement date of July 1, 2016. This valuation resulted in increases to the projected benefit obligations for the pension and other postretirement benefit plans of approximately $177 million and $20 million , respectively, a decrease in the fair value of pension plan assets of $10 million , and an increase in the fair value of other postretirement benefit plan assets of $1 million . The Company also recorded a related regulatory asset of $437 million related to unrecognized prior service cost and actuarial gain/loss, as it is probable that this amount will be recovered through future rates for the natural gas distribution utilities. The previously unrecognized prior service cost and actuarial gain/loss related to non-utility subsidiaries were eliminated through purchase accounting adjustments.

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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 periods presented and the benefit obligations as of the measurement date are presented below.

	Successor	Predecessor		
	July 1, 2016 through December 31,	January 1, 2016 through June 30,	Years Ended December 31,	
Assumptions used to determine net periodic costs:	**2016**	**2016**	2015	2014
Pension plans				
Discount rate – interest costs [(a)]	**3.21%**	**4.00%**	4.20%	5.00%
Discount rate – service costs [(a)]	**4.07**	**4.80**	4.20	5.00
Expected long-term return on plan assets	**7.75**	**7.80**	7.80	7.80
Annual salary increase	**3.50**	**3.70**	3.70	3.70
Pension band increase [(b)]	**2.00**	**2.00**	2.00	2.00
Other postretirement benefit plans				
Discount rate – interest costs [(a)]	**2.84%**	**3.60%**	4.00%	4.70%
Discount rate – service costs [(a)]	**3.96**	**4.70**	4.00	4.70
Expected long-term return on plan assets	**5.93**	**6.60**	7.80	7.80
Annual salary increase	**3.50**	**3.70**	3.70	3.70

(a) Effective January 1, 2016, the Company uses a spot rate approach to estimate the service cost and interest cost components. Previously, the Company estimated these components using a single weighted average discount rate.

(b) Only applicable to Nicor Gas union employees. The pension bands for the former Nicor plan reflect the negotiated rates of 2.0% for each of 2016 and 2017, in accordance with a March 2014 union agreement.

	Successor	Predecessor
Assumptions used to determine benefit obligations:	**December 31, 2016**	December 31, 2015
Pension plans		
Discount rate	**4.39%**	4.6%
Annual salary increase	**3.50**	3.7
Pension band increase [(*)]	**2.00**	2.0
Other postretirement benefit plans		
Discount rate	**4.15%**	4.4%
Annual salary increase	**3.50**	3.7

(*) Only applicable to Nicor Gas union employees. The pension bands for the former Nicor plan reflect the negotiated rates of 2.0% for each of 2016 and 2017, in accordance with a March 2014 union agreement.

The Company estimates the expected return on plans assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing, and historical performance. The Company also considers guidance from its investment advisors in making a final determination of its expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater or less than the assumed rate, it does not affect that year's annual pension or welfare plan cost; rather, this gain or loss reduces or increases future pension or welfare plan costs.

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An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2016 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	6.60%	4.50%	2038
Post-65 medical	8.40	4.50	2038
Post-65 prescription	8.40	4.50	2038

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 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Successor – December 31, 2016		
Benefit obligation	$ 14	$ 12
Service and interest costs	—	—

Pension Plans

The total accumulated benefit obligation for the pension plans was $1.1 billion at December 31, 2016 and $1.0 billion at December 31, 2015 . Changes in the projected benefit obligations and the fair value of plan assets for the successor period ended December 31, 2016 and for the predecessor periods ended June 30, 2016 and December 31, 2015 were as follows:

	Successor	Predecessor	
	July 1, 2016 through December 31, 2016	**January 1, 2016 through June 30, 2016**	2015
	(in millions)	*(in millions)*	
Change in benefit obligation			
Benefit obligation at beginning of period	**$ 1,244**	**$ 1,067**	$ 1,098
Service cost	**15**	**13**	28
Interest cost	**20**	**21**	45
Benefits paid	**(31)**	**(26)**	(49)
Actuarial loss (gain)	**(115)**	**169**	(55)
Balance at end of period	**1,133**	**1,244**	1,067
Change in plan assets			
Fair value of plan assets at beginning of period	**837**	**847**	906
Actual return (loss) on plan assets	**48**	**15**	(12)
Employer contributions	**129**	**1**	2
Benefits paid	**(31)**	**(26)**	(49)
Fair value of plan assets at end of period	**983**	**837**	847
Accrued liability	**$ 150**	**$ 407**	$ 220

At December 31, 2016 , the projected benefit obligations for the qualified and non-qualified pension plans were $1.1 billion and $39 million , respectively. All pension plan assets are related to the qualified pension plan.

NOTES (continued)
Southern Company Gas and Subsidiary Companies 2016 Annual Report

Amounts recognized in the consolidated balance sheets at December 31, 2016 and 2015 related to the Company's pension plans consist of the following:

	Successor	Predecessor
	2016	2015
	(in millions)	*(in millions)*
Other regulatory assets, deferred	**$ 267**	$ 88
Other deferred charges and assets	**58**	78
Other current liabilities	**(2)**	(4)
Employee benefit obligations	**(206)**	(294)

Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2016 and 2015 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2017 .

	Prior Service Cost	Net (Gain) Loss
	(in millions)	
Successor – Balance at December 31, 2016:		
Accumulated OCI	**$ —**	**$ (43)**
Regulatory assets (liabilities)	**(2)**	**269**
Total	**$ (2)**	**$ 226**
Predecessor – Balance at December 31, 2015:		
Accumulated OCI	$ (4)	$ 286
Regulatory assets	—	88
Total	$ (4)	$ 374
Estimated amortization in net periodic cost in 2017:		
Regulatory assets (liabilities)	**$ 1**	**$ (21)**

NOTES (continued)
Southern Company Gas and Subsidiary Companies 2016 Annual Report

The components of OCI and the changes in the balance of regulatory assets related to the defined benefit pension plans for the successor period ended December 31, 2016 and for the predecessor periods ended June 30, 2016 and December 31, 2015 are presented in the following table:

	Accumulated OCI	Regulatory Assets
	(in millions)	
Predecessor – Balance at December 31, 2014:	$ 301	$ 76
Net (gain) loss	—	22
Reclassification adjustments:		
Amortization of prior service costs	2	—
Amortization of net loss	(21)	(10)
Total reclassification adjustments	(19)	(10)
Total change	(19)	12
Predecessor – Balance at December 31, 2015:	$ 282	$ 88
Reclassification adjustments:		
Amortization of prior service costs	**1**	—
Amortization of net loss	**(9)**	**(4)**
Total reclassification adjustments	**(8)**	**(4)**
Total change	**(8)**	**(4)**
Predecessor – Balance at June 30, 2016:	**$ 274**	**$ 84**
Successor – Balance at July 1, 2016:	**$ —**	**$ 368**
Net (gain) loss	**(43)**	**(87)**
Reclassification adjustments:		
Amortization of prior service costs	—	**1**
Amortization of net loss	—	**(15)**
Total reclassification adjustments	—	**(14)**
Total change	**(43)**	**(101)**
Successor – Balance at December 31, 2016:	**$ (43)**	**$ 267**

Components of net periodic pension costs for the periods presented were as follows:

	Successor	Predecessor		
	July 1, 2016 through December 31,	**January 1, 2016 through June 30,**	Years Ended December 31,	
	2016	**2016**	2015	2014
	(in millions)	*(in millions)*		
Service cost	**$ 15**	**$ 13**	$ 28	$ 24
Interest cost	**20**	**21**	45	47
Expected return on plan assets	**(35)**	**(33)**	(65)	(65)
Amortization of regulatory assets	**13**	—	—	—
Amortization:				
Prior service costs	—	**(1)**	(2)	(2)
Net (gain)/loss	—	**13**	31	22
Net periodic pension cost	**$ 13**	**$ 13**	$ 37	$ 26

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.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2016 , estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2017	$ 71
2018	72
2019	73
2020	74
2021	74
2022 to 2026	363

Other Postretirement Benefits

Changes in the APBO and the fair value of plan assets for the successor period ended December 31, 2016 and for the predecessor periods ended June 30, 2016 and December 31, 2015 were as follows:

	Successor	Predecessor	
	July 1, 2016 through December 31, 2016	**January 1, 2016 through June 30, 2016**	2015
	(in millions)	*(in millions)*	
Change in benefit obligation			
Benefit obligation at beginning of period	**$ 338**	**$ 318**	$ 334
Service cost	**1**	**1**	2
Interest cost	**5**	**5**	13
Benefits paid	**(11)**	**(11)**	(20)
Actuarial loss (gain)	**(26)**	**24**	(13)
Retiree drug subsidy	**—**	**—**	1
Employee contributions	**1**	**1**	1
Balance at end of period	**308**	**338**	318
Change in plan assets			
Fair value of plan assets at beginning of period	**100**	**99**	99
Actual return (loss) on plan assets	**4**	**1**	1
Employee contributions	**1**	**1**	1
Employer contributions	**11**	**10**	17
Benefits paid	**(11)**	**(11)**	(20)
Retiree drug subsidy	**—**	**—**	1
Fair value of plan assets at end of year	**105**	**100**	99
Accrued liability	**$ 203**	**$ 238**	$ 219

Amounts recognized in the consolidated balance sheets at December 31, 2016 and 2015 related to the Company's other postretirement benefit plans consist of the following:

	Successor	Predecessor
	2016	2015
	(in millions)	*(in millions)*
Other regulatory assets, deferred	**$ 52**	$ 30
Employee benefit obligations	**(203)**	(219)

NOTES (continued)
Southern Company Gas and Subsidiary Companies 2016 Annual Report

Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2016 and 2015 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost. The estimated amortization of such amounts for 2017 is immaterial.

	Prior Service Cost	Net (Gain) Loss
	(in millions)	
Successor – Balance at December 31, 2016:		
Accumulated OCI	**$ —**	**$ (3)**
Regulatory assets (liabilities)	**(12)**	**64**
Total	**$ (12)**	**$ 61**
Predecessor – Balance at December 31, 2015:		
Accumulated OCI	$ —	$ 36
Regulatory assets (liabilities)	(15)	45
Total	$ (15)	$ 81

The components of OCI, along with the changes in the balance of regulatory assets (liabilities), related to the other postretirement benefit plans for the successor period ended December 31, 2016 and for the predecessor periods ended June 30, 2016 and December 31, 2015 are presented in the following table:

	Accumulated OCI	Regulatory Assets
	(in millions)	
Predecessor – Balance at December 31, 2014:	$ 36	$ 39
Net (gain) loss	2	(8)
Reclassification adjustments:		
Amortization of prior service costs	—	2
Amortization of net loss	(2)	(3)
Total reclassification adjustments	(2)	(1)
Total change	—	(9)
Predecessor – Balance at December 31, 2015:	$ 36	$ 30
Reclassification adjustments:		
Amortization of prior service costs	—	**1**
Amortization of net loss	**(1)**	**(1)**
Total reclassification adjustments	**(1)**	**—**
Total change	**(1)**	**—**
Predecessor – Balance at June 30, 2016:	**$ 35**	**$ 30**
Successor – Balance at July 1, 2016:	**$ —**	**$ 77**
Net (gain) loss	**(3)**	**(23)**
Reclassification adjustments:		
Amortization of prior service costs	—	**1**
Amortization of net loss	—	**(3)**
Total reclassification adjustments	—	**(2)**
Total change	**(3)**	**(25)**
Successor – Balance at December 31, 2016:	**$ (3)**	**$ 52**

Components of the other postretirement benefit plans' net periodic cost for the periods presented were as follows:

	Successor	Predecessor		
	July 1, 2016 through December 31,	**January 1, 2016 through June 30,**	Years Ended December 31,	
	2016	**2016**	2015	2014
	(in millions)	*(in millions)*		
Service cost	**$ 1**	**$ 1**	$ 2	$ 2
Interest cost	**5**	**5**	13	15
Expected return on plan assets	**(3)**	**(3)**	(7)	(7)
Amortization of regulatory assets	**2**	**—**	—	—
Amortization:				
Prior service costs	**—**	**(1)**	(3)	(3)
Net (gain)/loss	**—**	**2**	6	6
Net periodic postretirement benefit cost	**$ 5**	**$ 4**	$ 11	$ 13

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. At December 31, 2016 , estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2017	$ 20
2018	20
2019	21
2020	22
2021	22
2022 to 2026	111

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. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The assets of the AGL Resources Inc. Retirement Plan (AGL plan) were allocated 69% equity, 20% fixed income, 1% cash, and 10% other at December 31, 2016 compared to the Company's targets of 53% equity, 15% fixed income, 2% cash, and 30% other. The investment policy provides for variation around the target asset allocation in the form of ranges.

The assets of the Company's other postretirement benefit plan were allocated 74% equity, 23% fixed income, 1% cash, and 2% other at December 31, 2016 compared to the Company's targets of 72% equity, 24% fixed income, 1% cash, and 3% other. The investment policy provides for variation around the target asset allocation in the form of ranges.

The assets of the AGL plan and the Company's other postretirement benefit plan were each allocated 72% equity and 28% fixed income at December 31, 2015 compared to the Company's targets of 70% to 95% equity, 5% to 20% fixed income, and up to 10% cash. The investment policies provided for some variation in these targets in the form of ranges around the target.

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 for its pension plan assets. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for the successor period for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

The investment strategies for the predecessor periods followed a policy to preserve the plans' capital and maximize investment earnings in excess of inflation within acceptable levels of capital market volatility. To accomplish this goal, the plans' assets were managed to optimize long-term return while maintaining a high standard of portfolio quality and diversification. In developing the allocation policy for the assets of the pension and other postretirement benefit plans, the Company examined projections of asset returns and volatility over a long-term horizon. In connection with this analysis, the risk and return trade-offs of alternative asset classes and asset mixes were evaluated given long-term historical relationships as well as prospective capital market returns. The Company also conducted asset-liability studies to match projected asset growth with projected liability growth to determine whether there is sufficient liquidity for projected benefit payments. Asset mix guidelines were developed by incorporating the results of these analyses with an assessment of the Company's risk posture, and taking into account industry practices. The Company periodically evaluated its investment strategy to ensure that plan assets were sufficient to meet the benefit obligations of the plans. As part of the ongoing evaluation, the Company made changes to its targeted asset allocations and investment strategy.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2016 and 2015 . The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation for the successor period, 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 2016 tables are as follows:

- ***Domestic and international equity.*** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- ***Fixed income.*** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- ***Real estate investments, private equity, and special situations investments.*** Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market

capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation for the predecessor periods, 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.

The fair values of pension plan assets as of December 31, 2016 and 2015 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. For 2016, special situations (absolute return and hedge funds) investment assets are presented in the table below based on the nature of the investment.

	Fair Value Measurements Using				
Successor – 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 [(*)]	$ 142	$ 343	$ —	$ —	$ 485
International equity [(*)]	—	185	—	—	185
Fixed income:					
U.S. Treasury, government, and agency bonds	—	85	—	—	85
Corporate bonds	—	41	—	—	41
Pooled funds	—	66	—	—	66
Cash equivalents and other	12	5	—	83	100
Real estate investments	4	—	—	15	19
Private equity	—	—	—	2	2
Total	$ 158	$ 725	$ —	$ 100	$ 983

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

NOTES (continued)
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	Predecessor – As of December 31, 2015				
	Pension plans [a]				
In millions	Level 1	Level 2	Level 3	Total	% of total
Cash	**$ 4**	**$ —**	**$ —**	**$ 4**	**—%**
Equity securities:					
U.S. large cap [b]	$ 75	$ 199	$ —	$ 274	32%
U.S. small cap [b]	57	24	—	81	9%
International companies [c]	—	125	—	125	15%
Emerging markets [d]	—	28	—	28	3%
Total equity securities	**$ 132**	**$ 376**	**$ —**	**$ 508**	**59%**
Fixed income securities:					
Corporate bonds [e]	$ —	$ 91	$ —	$ 91	11%
Other (or gov't/muni bonds)	—	151	—	151	18%
Total fixed income securities	**$ —**	**$ 242**	**$ —**	**$ 242**	**29%**
Other types of investments:					
Global hedged equity [f]	$ —	$ —	$ 40	$ 40	5%
Absolute return [g]	—	—	42	42	5%
Private capital [h]	—	—	20	20	2%
Total other investments	**$ —**	**$ —**	**$ 102**	**$ 102**	**12%**
Total assets at fair value	**$ 136**	**$ 618**	**$ 102**	**$ 856**	**100%**
% of fair value hierarchy	16%	72%	12%	100%	

(a) Includes $9 million at December 31, 2015 of medical benefit (health and welfare) component for 401(h) accounts to fund a portion of the other retirement benefits.

(b) Includes funds that invest primarily in U.S. common stocks.

(c) Includes funds that invest primarily in foreign equity and equity-related securities.

(d) Includes funds that invest primarily in common stocks of emerging markets.

(e) Includes funds that invest primarily in investment grade debt and fixed income securities.

(f) Includes funds that invest in limited/general partnerships, managed accounts, and other investment entities issued by non-traditional firms or "hedge funds."

(g) Includes funds that invest primarily in investment vehicles and commodity pools as a "fund of funds."

(h) Includes funds that invest in private equity and small buyout funds, partnership investments, direct investments, secondary investments, directly/indirectly in real estate and may invest in equity securities of real estate related companies, real estate mortgage loans, and real estate mezzanine loans.

NOTES (continued)
Southern Company Gas and Subsidiary Companies 2016 Annual Report

The fair values of other postretirement benefit plan assets as of December 31, 2016 and 2015 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. For 2016, special situations (absolute return and hedge funds) investment assets are presented in the table below based on the nature of the investment.

	Fair Value Measurements Using				
Successor – 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 [*]	$ 3	$ 58	$ —	$ —	$ 61
International equity [*]	—	18	—	—	18
Fixed income:					
Pooled funds	—	23	—	—	23
Cash equivalents and other	1	—	—	2	3
Total	$ 4	$ 99	$ —	$ 2	$ 105

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

NOTES (continued)
Southern Company Gas and Subsidiary Companies 2016 Annual Report

	Predecessor – As of December 31, 2015				
	Welfare plans				
In millions	Level 1	Level 2	Level 3	Total	% of total
Cash	**$ 1**	**$ —**	**$ —**	**$ 1**	**1%**
Equity securities:					
U.S. large cap [(a)]	$ —	$ 52	$ —	$ 52	58%
U.S. small cap [(a)]	—	—	—	—	—%
International companies [(b)]	—	15	—	15	17%
Emerging markets [(c)]	—	—	—	—	—%
Total equity securities	**$ —**	**$ 67**	**$ —**	**$ 67**	**75%**
Fixed income securities:					
Corporate bonds [(d)]	$ —	$ 22	$ —	$ 22	24%
Other (or gov't/muni bonds)	—	—	—	—	—%
Total fixed income securities	**$ —**	**$ 22**	**$ —**	**$ 22**	**24%**
Other types of investments:					
Global hedged equity [(e)]	$ —	$ —	$ —	$ —	—%
Absolute return [(f)]	—	—	—	—	—%
Private capital [(g)]	—	—	—	—	—%
Total other investments	**$ —**	**$ —**	**$ —**	**$ —**	**—%**
Total assets at fair value	**$ 1**	**$ 89**	**$ —**	**$ 90**	**100%**
% of fair value hierarchy	1%	99%	—%	100%	

(a) Includes funds that invest primarily in U.S. common stocks.
(b) Includes funds that invest primarily in foreign equity and equity-related securities.
(c) Includes funds that invest primarily in common stocks of emerging markets.
(d) Includes funds that invest primarily in investment grade debt and fixed income securities.
(e) Includes funds that invest in limited/general partnerships, managed accounts, and other investment entities issued by non-traditional firms or "hedge funds."
(f) Includes funds that invest primarily in investment vehicles and commodity pools as a "fund of funds."
(g) Includes funds that invest in private equity and small buyout funds, partnership investments, direct investments, secondary investments, directly/indirectly in real estate and may invest in equity securities of real estate related companies, real estate mortgage loans, and real estate mezzanine loans.

Employee Savings Plan

SCS sponsors 401(k) defined contribution plans covering certain eligible Southern Company Gas employees. The AGL Resources Inc. 401(k) plans provide matching contributions of either 65% on up to 8% of an employee's eligible compensation, or a 100% matching contribution on up to 3% of an employee's eligible compensation, followed by a 75% matching contribution on up to the next 3% of an employee's eligible compensation. Total matching contributions made to the AGL Resources Inc. 401(k) plans for the successor period ended December 31, 2016 were $8 million and for the predecessor periods ended June 30, 2016 and December 31, 2015 and 2014 were $10 million , $16 million , and $14 million , respectively.

For employees not accruing a benefit under the AGL Resources Inc. Retirement Plan, additional contributions made to the 401(k) plans for the successor period ended December 31, 2016 were not material and for the predecessor periods ended June 30, 2016 and December 31, 2015 and 2014 were $2 million , $2 million , and $1 million , respectively.

3 . CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

Nicor Gas and Nicor Energy Services Company, wholly-owned subsidiaries of the Company, and Nicor Inc. are defendants in a putative class action initially filed in 2011 in state court in Cook County, Illinois. The plaintiffs purport to represent a class of the customers who purchased the Gas Line Comfort Guard product from Nicor Energy Services Company and variously allege that the marketing, sale, and billing of the Gas Line Comfort Guard product violated the Illinois Consumer Fraud and Deceptive Business Practices Act, constituting common law fraud and resulting in unjust enrichment of these entities. The plaintiffs seek, on

behalf of the classes they purport to represent, actual and punitive damages, interest, costs, attorney fees, and injunctive relief. On February 8, 2017, the judge denied the plaintiffs' motion for class certification and the Company's motion for summary judgment. The ultimate outcome of this matter cannot be determined at this time.

The Company is assessing its alleged involvement in an incident that occurred in one of its service territories that resulted in several deaths, injuries, and property damage. One of the Company's utilities has been named as one of the defendants in several lawsuits related to this incident. The Company has insurance that provides full coverage of any financial exposure in excess of $11 million that is related to this incident. During the successor period ended December 31, 2016 and the predecessor period ended December 31, 2015 , the Company recorded reserves for substantially all of its potential exposure from these cases. The ultimate outcome of this matter cannot be determined at this time.

The Company is subject to certain claims and legal actions arising in the ordinary course of business. The ultimate outcome of these matters and such pending or potential litigation against the Company cannot be determined 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

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including the handling and disposal of waste and releases of hazardous substances. Compliance with these environmental requirements involves significant capital and operating costs to clean up affected sites. The Company conducts studies to determine the extent of any required clean up and has recognized in its financial statements the costs to clean up known impacted sites. The natural gas distribution utilities in Illinois, New Jersey, Georgia, and Florida have each received authority from their applicable state regulatory agencies to recover approved environmental compliance costs through regulatory mechanisms.

The Company is subject to environmental remediation liabilities associated with 46 former MGP sites in five different states. Accrued environmental remediation costs of $426 million have been recorded in the consolidated balance sheets as of December 31, 2016 , $69 million of which is expected to be incurred over the next 12 months. These environmental remediation expenditures are recoverable from customers through rate mechanisms approved by the applicable state regulatory agencies, with the exception of one site representing $5 million of the total accrued remediation costs.

In September 2015, the EPA filed an administrative complaint and notice of opportunity for hearing against Nicor Gas. The complaint alleges violation of the regulatory requirements applicable to polychlorinated biphenyls in the Nicor Gas distribution system and the EPA seeks a total civil penalty of approximately $0.3 million . On January 26, 2017, the EPA notified Nicor Gas that it agreed to voluntarily dismiss its administrative complaint with prejudice and without payment of a civil penalty or other further obligation on the part of Nicor Gas.

The Company's ultimate environmental compliance strategy and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and the outcome of any legal challenges to the environmental rules. The ultimate outcome of these matters cannot be determined at this time.

In 2014, the Company reached a settlement with an insurance company for environmental claims relating to potential contamination at several MGP sites in New Jersey and North Carolina. The terms of the settlement required the insurance company to pay the Company a total of $77 million in two installments. The Company received a $45 million installment in 2014 and the remaining $32 million in July 2015. The New Jersey BPU approved the use of the insurance proceeds to reduce the regulatory assets associated with environmental remediation costs that otherwise would have been recovered from Elizabethtown Gas customers.

FERC Matters

At December 31, 2016, gas midstream operations was involved in three gas pipeline construction projects. These projects, along with the Company's existing pipelines, are intended to provide diverse sources of natural gas supplies to customers, resolve current and long-term supply planning for new capacity, enhance system reliability, and generate economic development in the areas served. One of these projects received FERC approval in August 2016. The remaining projects are pending FERC approval. The ultimate outcome of this matter cannot be determined at this time.

Regulatory Matters

Regulatory Infrastructure Programs

The Company has infrastructure improvement programs at several of its utilities. Descriptions of these programs are as follows:

Nicor Gas

In 2013, Illinois enacted legislation that allows Nicor Gas to provide more widespread safety and reliability enhancements to its distribution system. The legislation stipulates that rate increases to customer bills as a result of any infrastructure investments shall not exceed an annual average of 4.0% of base rate revenues. In 2014, the Illinois Commission approved the nine -year regulatory infrastructure program, Investing in Illinois, under which Nicor Gas implemented rates that became effective in March 2015.

Atlanta Gas Light

Atlanta Gas Light's four -year STRIDE program, which was approved by the Georgia PSC in 2013, is comprised of the Integrated System Reinforcement Program (i-SRP), the Integrated Customer Growth Program (i-CGP), and the Integrated Vintage Plastic Replacement Program (i-VPR), and consists of infrastructure development, enhancement, and replacement programs that are used to update and expand distribution systems and LNG facilities, improve system reliability, and meet operational flexibility and growth. STRIDE includes a monthly surcharge on firm customers that was approved by the Georgia PSC to provide recovery of the revenue requirement for the ongoing programs and the PRP. This surcharge began in January 2015 and will continue through 2025.

The i-SRP program authorized $445 million of capital spending for projects to upgrade Atlanta Gas Light's distribution system and LNG facilities in Georgia, improve its peak-day system reliability and operational flexibility, and create a platform to meet long-term forecasted growth. Under i-SRP, Atlanta Gas Light must file an updated 10 -year forecast of infrastructure requirements along with a new construction plan every three years for review and approval by the Georgia PSC. Atlanta Gas Light's most recent plan was approved in 2014. On August 1, 2016, Atlanta Gas Light filed a petition with the Georgia PSC for approval of a four -year extension of its i-SRP seeking approval to invest an additional $177 million to improve and upgrade its core gas distribution system in years 2017 through 2020. Capital investment associated with this filing for 2017 was included in the Georgia Ratemaking Adjustment Mechanism (GRAM) approved by the Georgia PSC on February 21, 2017. Capital investment in subsequent years under this filing will be included in future annual GRAM filings. See "Base Rate Cases" herein for additional information.

The i-CGP program authorized Atlanta Gas Light to spend $91 million on projects to extend its pipeline facilities to serve customers in areas without pipeline access and create new economic development opportunities in Georgia.

The i-VPR program, which was approved by the Georgia PSC in 2013, authorized Atlanta Gas Light to spend $275 million to replace 756 miles of aging plastic pipe that was installed primarily in the mid-1960s to the early 1980s. Atlanta Gas Light has identified approximately 3,300 miles of vintage plastic mains in its system that should be considered for potential replacement over the next 15 to 20 years under this program.

The orders for the STRIDE programs provide for recovery of all prudent costs incurred in the performance of the program. Atlanta Gas Light will recover from end-use customers, through billings to Marketers, the costs related to the programs net of any cost savings from the programs. All such amounts will be recovered through a combination of straight-fixed-variable rates and a STRIDE revenue rider surcharge. The regulatory asset represents recoverable incurred costs related to the programs that will be collected in future rates charged to customers through the rate riders. The future expected costs to be recovered through rates related to allowed, but not incurred costs, are recognized in an unrecognized ratemaking amount that is not reflected on the consolidated balance sheets. This allowed cost is primarily the equity return on the capital investment under the program. See "Unrecognized Ratemaking Amounts" herein for additional information.

Atlanta Gas Light capitalizes and depreciates the capital expenditure costs incurred from the STRIDE programs over the life of the assets. Operations and maintenance costs are expensed as incurred. Recoveries, which are recorded as revenue, are based on a formula that allows Atlanta Gas Light to recover operations and maintenance costs in excess of those included in its current base rates, depreciation, and an allowed rate of return on capital expenditures. However, Atlanta Gas Light is allowed the recovery of carrying costs on the under-recovered balance resulting from the timing difference. All components of Atlanta Gas Light's STRIDE program were approved by the Georgia PSC in connection with the new rate adjustment mechanism for Atlanta Gas Light. See "Base Rate Cases" herein for additional information.

Elizabethtown Gas

Elizabethtown Gas' extension of the Aging Infrastructure Replacement (AIR) enhanced infrastructure program effective in 2013 allowed for infrastructure investment of $115 million over four years , and is focused on the replacement of aging cast iron in its pipeline system. Carrying charges on the additional capital spend are being accrued and deferred for regulatory purposes at a WACC of 6.65% . In conjunction with the general base rate case filed with the New Jersey BPU on September 1, 2016, Elizabethtown Gas requested recovery of the AIR program. See "Base Rate Cases" herein for additional information.

In 2014, the New Jersey BPU approved Natural Gas Distribution Utility Reinforcement Effort (ENDURE), a program that improved Elizabethtown Gas' distribution system's resiliency against coastal storms and floods. Under the plan, Elizabethtown Gas invested $15 million in infrastructure and related facilities and communication planning over a one -year period from August 2014 through September 2015. Effective November 2015, Elizabethtown Gas increased its base rates for investments made under the program.

In September 2015, Elizabethtown Gas filed the Safety, Modernization and Reliability Tariff (SMART) plan with the New Jersey BPU seeking approval to invest more than $1.1 billion to replace 630 miles of vintage cast iron, steel, and copper pipeline, as well as 240 regulator stations. If approved, the program is expected to be completed by 2027. As currently proposed, costs incurred under the program would be recovered through a rider surcharge over a period of 10 years .

The ultimate outcome of these matters cannot be determined at this time.

Virginia Natural Gas

In 2012, the Virginia Commission approved the Steps to Advance Virginia's Energy (SAVE) program, an accelerated infrastructure replacement program, to be completed over a five -year period. This program includes a maximum allowance for capital expenditures of $25 million per year, not to exceed $105 million in total. SAVE is subject to annual review by the Virginia Commission. Virginia Natural Gas is recovering these program costs through a rate rider that became effective in 2012.

On March 9, 2016, the Virginia Commission approved an extension to the SAVE program to replace more than 200 miles of aging pipeline infrastructure. In accordance with the order approving the program, Virginia Natural Gas may invest up to $30 million in 2016 and up to $35 million annually through 2021. Additionally, Virginia Natural Gas may exceed the allowed program expenditures by up to a total of $5 million , of which $2 million was used in 2016.

Florida City Gas

In September 2015, the Florida PSC approved Florida City Gas' Safety, Access, and Facility Enhancement program, under which costs incurred for replacing aging pipes will be recovered through a rate rider with annual adjustments and true-ups. Under the program, Florida City Gas is authorized to spend $105 million over a 10 -year period on infrastructure relocation and enhancement projects.

Customer Refunds

In the third quarter 2016, Elizabethtown Gas provided direct per-customer rate credits totaling $17.5 million to its customers in accordance with the Merger approval from the New Jersey BPU. These rate credits were allocated among Elizabethtown Gas' customer classes based on the base rate revenues reflected in the rates that resulted from its most recent base rate proceeding.

In the fourth quarter 2016, Elkton Gas provided direct per-customer rate credits totaling $0.4 million to its customers in accordance with the Merger approval from the Maryland PSC. These rate credits were funded from an increase in the amount paid through Elkton Gas' asset management agreement.

PRP Settlement

In October 2015, Atlanta Gas Light received a final order from the Georgia PSC, which represented a resolution of all matters previously outstanding before the Georgia PSC, including a final determination of the true-up of allowed unrecovered revenue through December 2014. This order allows Atlanta Gas Light to recover $144 million of the $178 million unrecovered program revenue that was requested in its February 2015 filing. The remaining unrecovered amount related primarily to the previously unrecognized ratemaking amount, and did not have a material impact on the Company's consolidated financial statements. The Company also recognized $1 million of interest expense and $5 million in operations and maintenance expense related to the PRP on the Company's consolidated statements of income for the predecessor year ended December 31, 2015. See "Unrecognized Ratemaking Amounts" herein for additional information.

Atlanta Gas Light began recovering $144 million in October 2015 through the monthly PRP surcharge of $0.82 , or approximately $15 million annually, which increased by $0.81 on October 1, 2016. The monthly PRP surcharge is scheduled to increase by another $0.81 on October 1, 2017. As part of the Georgia PSC's approval, this increase will commence earlier with its implementation under GRAM. The PRP surcharge will remain effective until the earlier of the full recovery of the under-recovered amount or December 31, 2025.

One of the capital projects under the PRP experienced construction issues and Atlanta Gas Light was required to complete mitigation work prior to placing it in service. These mitigation costs will be included in future base rates in 2018. See "Base Rate Cases" herein for additional information on GRAM.

Provisions in the order resulted in the recognition of $5 million in operations and maintenance expense for the year ended December 31, 2015 on the Company's consolidated statements of income. Atlanta Gas Light continues to pursue contractual and legal claims against certain third-party contractors and will retain any amounts recorded. The ultimate outcome of this matter cannot be determined at this time.

Base Rate Cases

On December 5, 2016, Atlanta Gas Light filed a joint stipulation with the staff of the Georgia PSC seeking an annual rate review/adjustment mechanism, GRAM. This new mechanism will adjust rates up or down annually and will not collect revenue through special riders and surcharges for the STRIDE infrastructure programs. Also in this filing, Atlanta Gas Light requested an adjustment in base rates designed to collect an additional $20 million in annual revenues effective March 2017. On February 21, 2017, the Georgia PSC approved the joint stipulation and requested base rate adjustment.

On September 1, 2016, Elizabethtown Gas filed a general base rate case with the New Jersey BPU as required under its AIR program, requesting an increase in annual revenues of $19 million , based on an allowed ROE of 10.25% . The Company expects the New Jersey BPU to issue an order on the filing in the third quarter 2017.

On December 13, 2016, Virginia Natural Gas filed a notice of intent with the Virginia Commission as required at least 60 days prior to filing a general base rate case.

The ultimate outcome of these matters cannot be determined at this time.

Gas Cost Prudence Review

In 2014, the Illinois Commission staff and the CUB filed testimony in the Nicor Gas 2003 gas cost prudence review disputing certain gas loan transactions offered by Nicor Gas under its Chicago Hub services and requesting refunds of $18 million and $22 million , respectively. On February 10, 2016, the administrative law judge issued a proposed order affirming an original order by the Illinois Commission, which was approved by the Illinois Commission on March 23, 2016 and concluded this matter. The Illinois Commission approved the purchase gas adjustments for the years 2004 through 2007 on August 9, 2016 and for the years 2008 and 2009 on August 24, 2016. As a condition of these approvals, Nicor Gas agreed to revise the way in which interest is reflected in the calculations beginning in 2013. The Company does not expect this revision to have a material impact on its consolidated financial statements. The gas cost prudence reviews for years 2010 through 2015 are underway. The ultimate outcome of these matters cannot be determined at this time.

energySMART

In 2014, the Illinois Commission approved Nicor Gas' energySMART program, which outlines energy efficiency offerings and therm reduction goals with spending of $93 million over a three -year period that began in 2014. On December 7, 2016, new energy legislation was signed in Illinois that extended the current program through December 31, 2017.

Unrecognized Ratemaking Amounts

The following table illustrates the Company's authorized ratemaking amounts that are not recognized on its balance sheets. These amounts are primarily composed of an allowed equity rate of return on assets associated with certain of the Company's regulatory infrastructure programs. These amounts will be recognized as revenues in the Company's financial statements in the periods they are billable to customers.

	Successor	Predecessor
	December 31, 2016	December 31, 2015
	(in millions)	*(in millions)*
Atlanta Gas Light	**$ 110**	$ 103
Virginia Natural Gas	**11**	12
Elizabethtown Gas	**6**	4
Nicor Gas	**2**	3
Total	**$ 129**	$ 122

4 . JOINT OWNERSHIP AGREEMENTS

In 2014, the Company entered into two arrangements associated with the Dalton Pipeline. The first was a construction and ownership agreement through which the Company has a 50% undivided ownership interest jointly with The Williams Companies,

Inc. in the 115 -mile Dalton Pipeline that is being constructed to serve as an extension of the Transco natural gas pipeline system into northwest Georgia. The Company also entered into an agreement to lease its 50% undivided ownership in the Dalton Pipeline once it is placed in service. Under the lease, the Company will receive approximately $26 million annually for an initial term of 25 years . The lessee will be responsible for maintaining the pipeline during the lease term and for providing service to transportation customers under its FERC-regulated tariff. Engineering design work is complete and construction began in September 2016. At December 31, 2016 and December 31, 2015 , the Company's 50% share of construction costs was $124 million and $33 million , respectively, and is reflected in construction work in progress in the consolidated balance sheets.

Variable Interest Entities

SouthStar, previously a joint venture owned 85% by the Company and 15% by Piedmont, was the only VIE for which the Company was the primary beneficiary, prior to October 3, 2016 when the Company completed its purchase of Piedmont's remaining interest in SouthStar.

In December 2015, Georgia Natural Gas Company (GNG), a 100% -owned, direct subsidiary of the Company, notified Piedmont of its election, pursuant to a change in control of SouthStar, to purchase Piedmont's 15% interest in SouthStar at fair market value. This purchase was contingent upon the closing of the merger between Piedmont and Duke Energy Corporation (Duke Energy). On February 12, 2016, GNG and Piedmont entered into a letter agreement pursuant to which GNG agreed to pay Piedmont $160 million as the fair value for Piedmont's entire ownership interest in SouthStar. After Piedmont and Duke Energy completed their merger in October 2016, GNG completed its purchase of Piedmont's interest in SouthStar on October 3, 2016 and paid a purchase price of $160 million and $15 million for Piedmont's share of SouthStar's 2016 earnings through the date of acquisition.

At December 31, 2015, the Company presented the noncontrolling interest related to Piedmont's interest in SouthStar as a component in equity. During the first quarter 2016, the Company reclassified its noncontrolling interest, whose redemption was beyond the Company's control, as a contingently redeemable noncontrolling interest. Upon Piedmont and Duke Energy obtaining the necessary merger approval, the Company deemed this noncontrolling interest to be mandatorily redeemable and reclassified it to a current liability during the third quarter 2016. The roll-forwards of the redeemable noncontrolling interest for the successor period of July 1, 2016 through December 31, 2016 and the predecessor period of January 1, 2016 through June 30, 2016 are detailed below:

Predecessor –		*(in millions)*
Balance at December 31, 2015	$	—
Reclassification of noncontrolling interest to contingently redeemable noncontrolling interest		**46**
Net income attributable to noncontrolling interest		**14**
Distribution to noncontrolling interest		**(19)**
Balance at June 30, 2016	**$**	**41**
Successor –		*(in millions)*
Balance at July 1, 2016	**$**	**174**
Reclassification of contingently redeemable noncontrolling interest to mandatorily redeemable noncontrolling interest		**(174)**
Balance at December 31, 2016	$	—

The Company's cash flows used for financing activities include SouthStar's distribution to Piedmont for its portion of SouthStar's annual earnings from the previous year, which generally occurred in the first quarter of each year. For the successor period of July 1, 2016 through December 31, 2016 , SouthStar made a distribution of $15 million upon completion of the purchase of Piedmont's interest in SouthStar. For the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014 , SouthStar distributed to Piedmont $19 million , $18 million , and $17 million , respectively.

Equity Method Investments

The carrying amounts of the Company's equity method investments as of December 31, 2016 and 2015 and related income from those investments for the successor period ended December 31, 2016 and predecessor periods ended June 30, 2016 and December 31, 2015 and 2014 were as follows:

Balance Sheet Information	Successor	Predecessor
	December 31, 2016	December 31, 2015
	(in millions)	*(in millions)*
SNG	**$ 1,394**	$ —
Triton	**44**	49
Horizon Pipeline	**30**	14
PennEast Pipeline	**22**	9
Atlantic Coast Pipeline	**33**	7
Pivotal JAX LNG, LLC	**16**	—
Other	**2**	1
Total	**$ 1,541**	$ 80

Income Statement Information	Successor	Predecessor		
	July 1, 2016 through December 31, 2016	**January 1, 2016 through June 30, 2016**	2015	2014
	(in millions)	*(in millions)*		
SNG	**$ 56**	**$ —**	$ —	$ —
Triton	**2**	**1**	4	6
Horizon Pipeline	**1**	**1**	2	2
Atlantic Coast Pipeline	**1**	**—**	—	—
Total	**$ 60**	**$ 2**	$ 6	$ 8

SNG

On September 1, 2016, the Company, through a wholly-owned, indirect subsidiary, acquired a 50% equity interest in SNG, which is accounted for as an equity method investment. See Note 11 under "Investment in SNG" for additional information on this investment. Selected financial information of SNG since the Company's September 1, 2016 acquisition of a 50% equity interest is as follows:

Balance Sheet Information	As of December 31, 2016
	(in millions)
Current assets	$ 95
Property, plant, and equipment	2,451
Deferred charges and other assets	129
Total Assets	$ 2,675
Current liabilities	$ 588
Long-term debt	706
Other deferred charges and other liabilities	22
Total Liabilities	$ 1,316
Total Stockholders' Equity	1,359
Total Liabilities and Stockholders' Equity	$ 2,675

Income Statement Information	September 1, 2016 through December 31, 2016	
	(in millions)	
Revenues	$	230
Operating income	$	138
Net income	$	115

Other Investments

Triton

The Company has an investment in Triton, a cargo container leasing company, which is aggregated into its all other segment. Container equipment that is acquired by Triton is accounted for in tranches as defined in Triton's operating agreement and investors make capital contributions to Triton to invest in each of the tranches. As of December 31, 2016 , the Company had invested in seven tranches established by Triton.

Horizon Pipeline

The Company owns an interest in a joint venture with Natural Gas Pipeline Company of America that is regulated by the FERC. Horizon Pipeline operates a 70 -mile natural gas pipeline from Joliet, Illinois to near the Wisconsin/Illinois border. Nicor Gas typically contracts for 70% to 80% of the total annual capacity.

PennEast Pipeline

In 2014, the Company entered into a partnership in which it holds a 20% ownership interest in an interstate pipeline company formed to develop and operate a 118 -mile natural gas pipeline between New Jersey and Pennsylvania. The initial transportation capacity of 1.0 billion cubic feet (Bcf) per day, is under long-term contracts, mainly by public utilities and other market-serving entities, such as electric generation companies, in New Jersey, Pennsylvania, and New York.

Atlantic Coast Pipeline

In 2014, the Company entered into a project in which it holds a 5% ownership interest in an interstate pipeline company formed to develop and operate a 594 -mile natural gas pipeline in North Carolina, Virginia, and West Virginia with initial transportation capacity of 1.5 Bcf per day.

Pivotal JAX LNG, LLC

The Company owns a 50% interest in a planned LNG liquefaction and storage facility in Jacksonville, Florida. Once construction is complete and the facility is operational, it will be outfitted with a 2.0 million gallon storage tank with the capacity to produce in excess of 120,000 gallons of LNG per day.

5. INCOME TAXES

Subsequent to the Merger, Southern Company will file a consolidated federal income tax return and various combined and separate state income tax returns on behalf of the Company. 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. Prior to the Merger, the Company filed a U.S. federal consolidated income tax return and various state income tax returns.

NOTES (continued)
Southern Company Gas and Subsidiary Companies 2016 Annual Report

Current and Deferred Income Taxes

Details of income tax provisions for the successor period of July 1, 2016 through December 31, 2016 and the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014 are as follows:

	Successor	Predecessor		
	July 1, 2016 through December 31,	January 1, 2016 through June 30,	Years Ended December 31,	
	2016	2016	2015	2014
	(in millions)	*(in millions)*		
Federal —				
Current	$ —	$ 67	$ (13)	$ 111
Deferred	65	8	198	184
	65	75	185	295
State —				
Current	(16)	12	10	38
Deferred	27	—	18	17
	11	12	28	55
Total	$ 76	$ 87	$ 213	$ 350

Net cash payments (refunds) for income taxes for the successor period of July 1, 2016 through December 31, 2016 and the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014 were $23 million , $(100) million , $(26) million , and $422 million , respectively.

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:

	Successor	Predecessor
	2016	2015
	(in millions)	*(in millions)*
Deferred tax liabilities —		
Accelerated depreciation	$ 1,954	$ 1,820
Property basis differences	311	283
Regulatory assets associated with employee benefit obligations	125	44
Other	164	215
Total	2,554	2,362
Deferred tax assets —		
Federal net operating loss	59	—
Federal effect of state deferred taxes	42	62
Employee benefit obligations	165	164
Other	332	212
Total	598	438
Less valuation allowances	(19)	(19)
Total, net of valuation allowances	579	419
Accumulated deferred income taxes, net	$ 1,975	$ 1,943

In November 2015, the FASB issued ASU 2015-17, which simplifies the presentation of deferred income taxes. See Note 1 under "Recently Issued Accounting Standards" for additional information.

At December 31, 2016 , the tax-related regulatory liabilities to be credited to customers were $22 million . These liabilities are primarily attributable to unamortized ITCs.

Deferred federal and state 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 $1 million for the successor period of July 1, 2016 through December 31, 2016 and, for the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014, were $1 million , $2 million , and $2 million , respectively. At December 31, 2016 , all ITCs available to reduce federal income taxes payable had been utilized.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	Successor	Predecessor		
	July 1, 2016 through December 31,	**January 1, 2016 through June 30,**	Years Ended December 31,	
	2016	**2016**	2015	2014
Federal statutory rate	**35.0%**	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**4.0**	**3.5**	3.4	3.8
Other	**1.0**	**(0.9)**	(2.0)	(1.2)
Effective income tax rate	**40.0%**	**37.6%**	36.4%	37.6%

The Company's effective tax rates for the successor period of July 1, 2016 through December 31, 2016 and the predecessor period of January 1, 2016 through June 30, 2016 were impacted by certain nondeductible Merger-related expenses. The effective tax rate for the successor period of July 1, 2016 through December 31, 2016 was also impacted by certain nondeductible expenses associated with change-in-control compensation charges.

On March 30, 2016, the FASB issued ASU 2016-09, which changes the accounting for income taxes for share-based payment award transactions. Entities are required to recognize all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation as income tax expense or benefit in the income statement. The adoption of ASU 2016-09 did not have a material impact on the Company's overall effective tax rates. See Note 1 under "Recently Issued Accounting Standards" for additional information.

Unrecognized Tax Benefits

The Company has no unrecognized tax benefits for any period presented. The Company classifies interest on tax uncertainties as interest expense; however, the Company had no accrued interest or penalties for unrecognized tax benefits for any period presented.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months. The settlement of federal and state audits could impact the balances. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

On July 1, 2016, the Company became a wholly-owned subsidiary of Southern Company, which is a participant in the Compliance Assurance Process of the IRS. The audits for the Company by the IRS or any state have either concluded, or the statute of limitations has expired with respect to income tax examinations, for years prior to 2012.

6 . FINANCING

Southern Company Gas' 100% -owned subsidiary, Southern Company Gas Capital, was established to provide for certain of Southern Company Gas' ongoing financing needs through a commercial paper program, the issuance of various debt, hybrid securities, and other financing arrangements. Southern Company Gas fully and unconditionally guarantees all debt issued by Southern Company Gas Capital and the gas facility revenue bonds issued by Pivotal Utility Holdings. Nicor Gas is not permitted by regulation to make loans to affiliates or utilize Southern Company Gas Capital for its financing needs.

Securities Due Within One Year

The current portion of long-term debt at December 31, 2016 is composed of the portion of its long-term debt due within the next 12 months. At December 31, 2016 , the Company had $22 million of medium-term notes due within one year, consisting of

medium-term notes of Atlanta Gas Light. At December 31, 2015 , the Company had $545 million of first mortgage bonds and senior notes due within one year.

Certain of the Company's senior notes with a principal amount of $275 million were subject to change-in-control provisions that were triggered by the Merger. Under the applicable note purchase agreement, Southern Company Gas Capital was required to provide notice to the holders of these notes of the change in control and offer to prepay these notes in August 2016. None of the holders of these notes accepted the offer for prepayment. These senior notes remained on their original payment schedules and included $120 million aggregate principal amount of Series A Floating Rate notes that were repaid at maturity on October 27, 2016 and $155 million aggregate principal amount of 3.50% Senior Notes due October 27, 2018.

Long-Term Debt

Long-term debt of the Company at December 31, 2016 and 2015 consisted of Series A, Series B, and Series C medium-term notes of Atlanta Gas Light; senior notes of Southern Company Gas Capital; first mortgage bonds of Nicor Gas; and gas facility revenue bonds of Pivotal Utility Holdings. Southern Company Gas fully and unconditionally guarantees all of Southern Company Gas Capital's senior notes and Pivotal Utility Holdings' gas facility revenue bonds. Additionally, substantially all of Nicor Gas' properties are subject to the lien of the indenture securing its first mortgage bonds. The majority of the long-term debt matures after fiscal year 2021.

The amount of medium-term notes outstanding at December 31, 2016 and December 31, 2015 was $159 million and $181 million , respectively.

Maturities through 2021 applicable to total long-term debt are as follows: $22 million in 2017; $155 million in 2018; $350 million in 2019; $330 million in 2021; and thereafter $3.9 billion . There are no material scheduled maturities in 2020.

First Mortgage Bonds

The first mortgage bonds of Nicor Gas have been issued with maturities ranging from 2019 to 2038.

In February and May 2016, $75 million and $50 million , respectively, of Nicor Gas' first mortgage bonds matured and were repaid using the proceeds from commercial paper borrowings.

In June 2016, Nicor Gas issued $250 million aggregate principal amount of first mortgage bonds with the following terms: $100 million at 2.66% due June 20, 2026, $100 million at 2.91% due June 20, 2031, and $50 million at 3.27% due June 20, 2036. The proceeds were used to repay short-term indebtedness incurred under the Nicor Gas commercial paper program and for other working capital needs. The amount of first mortgage bonds outstanding at December 31, 2016 and December 31, 2015 was $625 million and $375 million , respectively.

Gas Facility Revenue Bonds

Pivotal Utility Holdings is party to a series of loan agreements with the New Jersey Economic Development Authority and Brevard County, Florida under which five series of gas facility revenue bonds have been issued with maturities ranging from 2022 to 2033. These revenue bonds are issued by state agencies or counties to investors, and proceeds from each issuance then are loaned to Pivotal Utility Holdings. The amount of gas facility revenue bonds outstanding at December 31, 2016 and December 31, 2015 was $200 million .

Senior Notes

In May 2016, Southern Company Gas Capital issued $350 million aggregate principal amount of 3.25% Senior Notes due June 15, 2026, which are guaranteed by Southern Company Gas. The proceeds were used to repay at maturity $300 million aggregate principal amount of 6.375% Senior Notes due July 15, 2016 and for general corporate purposes.

In September 2016, Southern Company Gas Capital issued $350 million aggregate principal amount of 2.45% Senior Notes due October 1, 2023 and $550 million aggregate principal amount of 3.95% Senior Notes due October 1, 2046, both of which are guaranteed by Southern Company Gas. The proceeds were used to repay a $360 million promissory note issued to Southern Company for the purpose of funding a portion of the purchase price for a 50% equity interest in SNG, to fund the purchase of Piedmont's interest in SouthStar, to make a voluntary contribution to the pension plan, to repay at maturity $120 million aggregate principal amount of Series A Floating Rate Senior Notes due October 27, 2016, and for general corporate purposes. The amount of senior notes outstanding at December 31, 2016 and December 31, 2015 was $3.7 billion and $2.5 billion , respectively.

Dividend Restrictions

By regulation, Nicor Gas is restricted, to the extent of its retained earnings balance, in the amount it can dividend or loan to affiliates and is not permitted to make money pool loans to affiliates. Elizabethtown Gas is restricted by its dividend policy as established by the New Jersey BPU in the amount it can dividend to its parent company to the extent of 70% of its quarterly net income. Additionally, as stipulated in the New Jersey BPU's order approving the Merger, Southern Company Gas is prohibited from paying dividends to its parent company, Southern Company, if Southern Company Gas' senior unsecured debt rating falls below investment grade. As of December 31, 2016, the amount of subsidiary retained earnings restricted for dividend payment totaled $688 million .

Bank Credit Arrangements

Credit Facilities

Bank credit arrangements under the Southern Company Gas Credit Facility and the Nicor Gas Credit Facility provide liquidity support to Southern Company Gas Capital's and Nicor Gas' commercial paper borrowings. The Nicor Gas Credit Facility is restricted for working capital needs of Nicor Gas. In October 2015, the Company entered into agreements to amend and extend the Southern Company Gas Credit Facility and the Nicor Gas Credit Facility. Under the terms of these agreements, the Company extended the maturity dates of the Southern Company Gas Credit Facility and the Nicor Gas Credit Facility to November 9, 2018 and December 14, 2018, respectively. One of the banks elected not to participate in this extension and its total commitment of $75 million will continue through the fourth quarter 2017. The Company also modified the credit facilities to provide for the limited consent by the lenders to the Merger with Southern Company. Additionally, the Company made similar changes to its Bank Rate Mode Covenants Agreement relating to the Pivotal Utility Holdings gas facility revenue bonds.

At December 31, 2016 , committed credit arrangements with banks were as follows:

	Successor					
	Expires				Expires Within One Year	
Company	2017	2018	Total	Unused	Term Out	No Term Out
	(in millions)		(in millions)		(in millions)	
Southern Company Gas Capital	$ 49	$ 1,251	$ 1,300	$ 1,249	$ —	$ 49
Nicor Gas	26	674	700	700	—	26
Total	$ 75	$ 1,925	$ 2,000	$ 1,949	$ —	$ 75

The Southern Company Gas Credit Facility and the Nicor Gas Credit Facility included in the table above each contain a covenant that limits the ratio of debt to capitalization (as defined in each Facility) to a maximum of 70% and contain cross acceleration provisions to other indebtedness (including guarantee obligations) of the applicable company. At December 31, 2016 , the Company and Nicor Gas were in compliance with their respective debt limit covenants.

Commercial Paper Programs

The Company maintains commercial paper programs at Southern Company Gas Capital and at Nicor Gas that consist of short-term, unsecured promissory notes. Nicor Gas' commercial paper program supports working capital needs at Nicor Gas as Nicor Gas is not permitted to make money pool loans to affiliates. All of the Company's other subsidiaries benefit from Southern Company Gas Capital's commercial paper program. Commercial paper is included in notes payable in the consolidated balance sheets.

Details of commercial paper borrowings outstanding were as follows:

	Commercial Paper at the End of the Period	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
Successor – December 31, 2016:		
Southern Company Gas Capital	**$ 733**	**1.09%**
Nicor Gas	**524**	**0.95%**
Total	**$ 1,257**	**1.03%**
Predecessor – December 31, 2015:		
Southern Company Gas Capital	$ 471	0.71%
Nicor Gas	539	0.52%
Total	$ 1,010	0.60%

7. COMMITMENTS

Pipeline Charges, Storage Capacity, and Gas Supply

Pipeline charges, storage capacity, and gas supply include charges recoverable through a natural gas cost recovery mechanism, or alternatively, billed to Marketers and demand charges associated with Sequent. The gas supply balance includes amounts for Nicor Gas' and SouthStar's gas commodity purchase commitments of 33 million mmBtu at floating gas prices calculated using forward natural gas prices at December 31, 2016 and valued at $106 million . The Company provides guarantees to certain gas suppliers for certain of its subsidiaries in support of payment obligations.

Expected future contractual obligations for pipeline charges, storage capacity, and gas supply that are not recognized on the balance sheets as of December 31, 2016 were as follows:

	Pipeline Charges, Storage Capacity, and Gas Supply
	(in millions)
2017	$ 822
2018	602
2019	447
2020	394
2021	352
2022 and thereafter	2,591
Total	$ 5,208

Operating Leases

The Company has operating lease agreements with various terms and expiration dates primarily for real estate. Total rent expense was $8 million , $6 million , $12 million , and $13 million for the successor period of July 1, 2016 through December 31, 2016 and the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014, respectively. The Company includes any step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease terms.

As of December 31, 2016 , the Company's estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments	
	(in millions)	
2017	$	18
2018		17
2019		16
2020		15
2021		15
2022 and thereafter		38
Total	$	119

Financial Guarantees

AGL Equipment Leasing Inc. (AEL), a wholly-owned subsidiary of the Company, holds the Company's interest in Triton and has an obligation to restore to zero any deficit in its equity account for income tax purposes in the unlikely event that Triton is liquidated and a deficit balance remains. This obligation was not impacted by the 2014 sale of Tropical Shipping and continues for the life of the Triton partnerships. Any payment is effectively limited to the net assets of AEL, which was less than $1 million at December 31, 2016 . The Company believes the likelihood of any such payment by AEL is remote and, as such, no liability has been recorded for this obligation at December 31, 2016 .

Indemnities

In certain instances, the Company has undertaken to indemnify current property owners and others against costs associated with the effects and/or remediation of contaminated sites for which it may be responsible under applicable federal or state environmental laws, generally with no limitation as to the amount. These indemnifications relate primarily to ongoing coal tar cleanup. See Note 3 under "Environmental Matters" for additional information regarding these matters. The Company believes that the likelihood of payment under its other environmental indemnifications is remote. No liability has been recorded for such indemnifications as the fair value was inconsequential at inception.

8. STOCK COMPENSATION

Stock-Based Compensation

Successor

At the effective time of the Merger, each share of Southern Company Gas common stock, other than certain excluded shares, was converted into the right to receive $66 in cash, without interest. Also at the effective time of the Merger:

- Southern Company Gas' outstanding restricted stock units, restricted stock awards, and non-employee director stock awards were deemed fully vested and were canceled and converted into the right to receive an amount in cash equal to the product of (i) the total number of shares of Southern Company Gas' common stock subject to such award and (ii) the Merger consideration of $66 per share;
- Southern Company Gas' outstanding stock options, all of which were fully vested, were canceled and converted into the right to receive an amount in cash equal to the product of (i) the total number of shares of Southern Company Gas' common stock subject to such options and (ii) the excess of the Merger consideration of $66 per share over the applicable exercise price per share of such options; and
- each outstanding award of a performance share unit was converted into an award of Southern Company's restricted stock units (RSUs).

In conjunction with the Merger, stock-based compensation, in the form of Southern Company restricted stock and performance share units, was granted to certain executives of the Company through the Southern Company Omnibus Incentive Compensation Plan.

Southern Company Restricted Stock Awards

Under the terms of the RSU awards, the employees received a specified number of RSUs that vest when the employees have satisfied the requisite service period(s) at which time the employee receives Southern Company common stock. The terms of the

award require the employee to be continuously employed through the original three -year vesting schedule of the award being replaced.

For the successor period ended December 31, 2016 , employees of the Company were granted 742,461 RSUs. The grant-date fair value of the RSUs granted was $53.83 , based on the closing stock price of Southern Company common stock on the date of the grant. As a portion of the fair value of the award related to pre-combination service, the grant date fair value was allocated to pre- or post-combination service and accounted for as Merger consideration or compensation cost, respectively. Approximately $13 million of the grant date fair value was allocated to Merger consideration. The remaining fair value of $12 million will be recognized as compensation expense on a straight-line basis over the remaining vesting period.

The compensation cost related to the grant of RSUs to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. For the successor period of July 1, 2016 through December 31, 2016 , total compensation cost for RSUs recognized in income was $13 million , wi th the related tax benefit also recognized in income of $4 million . As of December 31, 2016 , $12 million of total unrecognized compensation cost related to RSUs will be recognized over a weighted-average period of approximately 20 months . See "Performance Share Unit Awards" herein for additional information.

Change in Control Awards

Southern Company awarded performance share units to certain employees remaining with the Company in lieu of certain change in control benefits the employee was entitled to receive following the Merger (change-in-control awards). Shares of Southern Company common stock and/or cash equal to the dollar value of the change-in-control benefit will vest and be issued one-third each year as long as the employee remains in service with the Company, or any of its affiliates, at each vest date. In addition to the change-in-control benefit, Southern Company common stock could be issued to the employees at the end of a performance period with the number of shares issued ranging from 0% to 100% of the target number of performance share units granted, based on achievement of certain Southern Company common stock price metrics, as well as performance goals established by the Compensation Committee of the Southern Company Board of Directors (achievement shares).

The change-in-control benefits are accounted for as a liability award with the fair value equal to the guaranteed dollar value of the change-in-control benefit. The grant-date fair value of the achievement portion of the award was determined using a Monte Carlo simulation model to estimate the number of achievement shares expected to vest based on the Southern Company common stock price. The expected payout is reevaluated annually with expense recognized to date increased or decreased proportionately based on the expected performance. The compensation expense ultimately recognized for the achievement shares will be based on the actual performance.

For the successor period July 1, 2016 through December 31, 2016 , total compensation cost for the change-in-control awards recognized in income was $4 million , with less than $1 million related tax benefit recognized in income. The compensation cost related to the grant of Southern Company change-in-control benefit and achievement shares to the Company's employees are recognized in the Company's financial statements with a corresponding credit to a liability or equity, representing a capital contribution from Southern Company, respectively. As of December 31, 2016 , $20 million of total unrecognized compensation cost related to change in control awards will be recognized over a weighted-average period of approximately 23 months .

Predecessor

For the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014 , the employees of Southern Company Gas and subsidiaries participated in the AGL Resources Inc. Omnibus Performance Incentive Plan, as amended and restated.

The AGL Resources Inc. Omnibus Performance Incentive Plan, as amended and restated, and the Long-Term Incentive Plan (1999) provided for the grant of incentive and nonqualified stock options, stock appreciation rights, shares of restricted stock, restricted stock units, performance cash awards, and other stock-based awards to officers and key employees. Under the AGL Resources Inc. Omnibus Performance Incentive Plan, as of December 31, 2015 , the number of shares that were issuable upon exercise of outstanding stock options, warrants, and rights was 359,586 shares. Under the Long-Term Incentive Plan (1999), as of December 31, 2015 , the number of shares that were issuable upon exercise of outstanding stock options, warrants, and rights was 80,600 shares. The maximum number of shares that were available for future issuance under the AGL Resources Inc. Omnibus Performance Incentive Plan was 3,513,992 shares, which included 1,514,116 shares previously available under the Nicor Inc. 2006 Long-Term Incentive Plan, as amended, pursuant to New York Stock Exchange rules. Effective July 1, 2016, all Southern Company Gas shares of stock were canceled and/or converted as a result of the Merger. No further grants will be made from the Long-Term Incentive Plan (1999) or the AGL Resources Inc. Omnibus Performance Incentive Plan, as amended and restated.

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For the predecessor periods, the Company recognized stock-based compensation expense for its stock-based awards over the requisite service period based on the estimated fair value at the date of grant for its stock-based awards using the modified prospective method. These stock awards included: stock options, stock and restricted stock awards, and performance units (restricted stock units, performance share units, and performance cash units).

Performance-based stock awards and performance units contained market and performance conditions. Stock options, restricted stock awards, and performance units also contained a service condition. The Company estimated forfeitures over the requisite service period when recognizing compensation expense. These estimates were adjusted to the extent that actual forfeitures differ, or were expected to materially differ, from such estimates. Excess tax benefits were reported as a financing cash inflow. The difference between the proceeds from the exercise of the Company's stock-based awards and the par value of the stock was recorded within additional paid-in capital.

Southern Company Gas granted stock awards with a grant price that was equal to the fair market value on the date of the grant. Fair market value was defined under the terms of the applicable plans as the closing price per share of Southern Company Gas' common stock on the grant date. For the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014 , total compensation cost for cash and stock-based awards recognized in income was $24 million , $40 million , and $24 million , respectively, with related tax benefits also recognized in income, which were immaterial.

Incentive and Nonqualified Stock Options

The stock options that the Company granted prior to the Merger had a three -year vesting period and expired ten years after the date of grant. The exercise price for stock options granted equaled the stock price of Southern Company Gas common stock on the date of grant. Participants realized value from option grants only to the extent that the fair market value of the Company's common stock on the date of exercise of the option exceeded the fair market value of the common stock on the date of the grant. No stock options have been issued under the plan since 2009.

The Company used shares purchased under its 2006 share repurchase program to satisfy exercises to the extent that repurchased shares were available. Otherwise, the Company issued new shares from its authorized common stock.

The Company measured compensation cost related to stock options based on the fair value of these awards at their date of grant using the Black-Scholes option-pricing model. For the predecessor period ended December 31, 2015 , the Company had no unrecognized compensation costs related to stock options. Cash received from stock option exercises for the predecessor periods ended June 30, 2016 and December 31, 2015 were less than $1 million and $5 million , respectively, and the income tax benefit from stock option exercises was immaterial for both periods.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014 , the total intrinsic value of options exercised was $3 million , $13 million , and $4 million , respectively.

Effective July 1, 2016, all of the Company's outstanding stock options, all of which were fully vested, were canceled and converted into the right to receive an amount in cash equal to the product of (i) the total number of shares of Southern Company Gas' common stock subject to such options and (ii) the excess of the Merger consideration of $66 per share over the applicable exercise price per share of such options.

Restricted Stock Units

A restricted stock unit was an award that represented the opportunity to receive a specified number of shares of the Company's common stock, subject to the achievement of certain pre-established performance criteria. For the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014 , the Company granted 25,166 , 47,546 , and 44,272 , respectively, of restricted stock units (including dividends) to certain employees. At the effective time of the Merger, all 65,042 restricted stock units outstanding were deemed fully vested and were canceled and converted into the right to receive an amount in cash equal to the product of (i) the total number of shares of Southern Company Gas' common stock subject to such award and (ii) the Merger consideration of $66 per share.

Performance Share Unit Awards

A performance share unit award represented the opportunity to receive cash and shares subject to the achievement of certain pre-established performance criteria. For the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014 , the Company granted performance share unit awards to certain officers. The Company's 2016 and 2015 performance share units had two performance measures. One measure, which accounted for 75% , related to the Company's total shareholder return relative to a group of peer companies. The second measure, which accounted for 25% , related to the Company's earnings per share, excluding wholesale gas services, over the three -year performance period. The 2014 performance share units were measured entirely based on the Company's total shareholder return relative to a group of peer companies.

At the effective time of the Merger, each outstanding performance share unit was converted into an award of Southern Company's restricted stock units. The conversion ratio was the product of (i) the greater of (a) 125% of the number of units underlying such award based on target level achievement of all relevant performance goals and (b) the number of units underlying such award based on the actual level of achievement of all relevant performance goals against target and (ii) an exchange ratio based on the Merger consideration of $66 per share as compared to the volume-weighted average price per share of Southern Company common stock. The resulting Southern Company restricted stock units will follow the vesting schedule and payment terms, and otherwise be issued on similar terms and conditions, as were applicable to such performance share unit awards, subject to certain exceptions. See "Southern Company Restricted Stock Awards" for additional information.

Stock and Restricted Stock Awards

The compensation cost of both stock awards and restricted stock awards was equal to the grant date fair value of the awards, recognized over the requisite service period. No other assumptions were used to value the awards. The Company referred to restricted stock as an award of Company common stock subject to time-based vesting or achievement of performance measures. Prior to vesting, restricted stock awards were subject to certain transfer restrictions and forfeiture upon termination of employment.

Restricted Stock Awards — Employees

Total unvested restricted stock awards outstanding as of December 31, 2015 were 398,832 . During 2016, 303,618 restricted stock awards were granted, 699,960 restricted stock awards were vested, and 2,466 restricted stock awards were forfeited. At the effective time of the Merger, Southern Company Gas' outstanding restricted stock awards were deemed fully vested and were canceled and converted into the right to receive an amount in cash equal to the product of (i) the total number of shares of Southern Company Gas' common stock subject to such award and (ii) the Merger consideration of $66 per share.

9 . FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement. See Note 1 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 [a][b]				
Successor – 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	$ 338	$ 239	$ —	$ —	$ 577
Liabilities:					
Energy-related derivatives	$ 345	$ 224	$ —	$ —	$ 569

(a) Energy-related derivatives excludes $4 million associated with certain weather derivatives accounted for based on intrinsic value rather than fair value.

(b) Energy-related derivatives excludes cash collateral of $62 million .

As of December 31, 2015 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

	Fair Value Measurements Using [a][b]				
Predecessor – As of December 31, 2015	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Assets:					
Energy-related derivatives	$ 53	$ 113	$ —	$ —	$ 166
Interest rate derivatives	—	9	—	—	9
Total	$ 53	$ 122	$ —	$ —	$ 175
Liabilities:					
Energy-related derivatives	$ 63	$ 46	$ —	$ —	$ 109

(a) Energy-related derivatives excludes $10 million associated with certain weather derivatives accounted for based on intrinsic value rather than fair value.
(b) Energy-related derivatives excludes cash collateral of $96 million .

Valuation Methodologies

The energy-related derivatives primarily consist of exchange-traded financial products for natural gas, 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, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard OTC products that are valued using observable market data and assumptions commonly used by market participants. See Note 10 for additional information on how these derivatives are used.

Debt

The Company's long-term debt is recorded at amortized cost, including the fair value adjustments at the effective date of the Merger. The Company amortizes the fair value adjustments over the lives of the respective bonds. The following table presents the carrying amount and fair value of the Company's long-term debt as of December 31:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt, including securities due within one year:		
Successor – As of December 31, 2016	**$ 5,281**	**$ 5,491**
Predecessor – As of December 31, 2015	$ 3,820	$ 4,066

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates available to the Company.

10. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk, interest rate risk, and weather 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. Wholesale gas operations use various contracts in its commercial activities that generally meet the definition of derivatives. For other businesses, the Company's policy is that derivatives are to be used primarily for hedging purposes. In both cases, the Company mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net basis. See Note 9 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to natural gas price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, gas distribution operations has limited exposure to market volatility in prices of natural gas. The Company manages fuel-hedging programs, implemented per the guidelines of the natural gas distribution utilities' respective state regulatory agencies, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. However, the Company retains exposure to price changes that can, in a volatile energy market, be extremely material and can adversely affect the Company.

The Company also enters into weather derivative contracts as economic hedges of adjusted operating margins in the event of warmer-than-normal weather. Exchange-traded options are carried at fair value, with changes reflected in operating revenues. Non-exchange-traded options are accounted for using the intrinsic value method. Changes in the intrinsic value for non-exchange-traded contracts are reflected in the statements of income.

Energy-related derivative contracts are accounted for under one of three methods:

- *Regulatory Hedges* — Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in the cost of natural gas as the underlying natural gas is used in operations and ultimately recovered through the respective cost recovery clauses.
- *Cash Flow Hedges* — Gains and losses on energy-related derivatives designated as cash flow hedges (which are mainly used to hedge anticipated purchases and sales) are initially deferred in other OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* — Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income in the period of change.

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 natural gas industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2016 , the net volume of energy-related derivative contracts for natural gas positions totaled 157 million mmBtu for the Company, together with the longest hedge date of 2018 over which the Company is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest non-hedge date of 2022 for derivatives not designated as hedges.

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to earnings for the next 12-month period ending December 31, 2017 are immaterial.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings, with any ineffectiveness recorded directly to earnings. Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value gains or losses are both recorded directly to earnings, providing an offset, with any difference representing ineffectiveness. Fair value gains or losses on derivatives that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

In January 2015, the Company executed $800 million in notional value of 10 -year and 30 -year fixed-rate forward-starting interest rate swaps to hedge potential interest rate volatility prior to its issuances of long-term debt in the fourth quarter 2015 and during 2016. The Company designated the forward-starting interest rate swaps, which were settled in conjunction with the debt issuances, as cash flow hedges. The Company settled $200 million of these interest rate swaps in November 2015 for an immaterial loss, $400 million upon pricing the senior notes in May 2016 at a loss of $26 million , and the remaining $200 million upon pricing the senior notes in September 2016 at a loss of $35 million . Due to the application of acquisition accounting, only $5 million of the pre-tax loss incurred and deferred in the successor period will be amortized to interest expense through 2046, which is immaterial on an annual basis.

Derivative Financial Statement Presentation and Amounts

The derivative contracts of the Company are subject to master netting arrangements or similar agreements and are reported net in the financial statements. Some of these energy-related and interest rate derivative contracts may contain certain provisions that

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permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements.

At December 31, 2016 and 2015 , the fair value of energy-related derivatives and interest rate derivatives was reflected in the consolidated balance sheets as follows:

		Asset Derivatives			**Liability Derivatives**	
		Successor	Predecessor		**Successor**	Predecessor
Derivative Category	**Balance Sheet Location**	**December 31, 2016**	December 31, 2015	**Balance Sheet Location**	**December 31, 2016**	December 31, 2015
		(in millions)	*(in millions)*		*(in millions)*	*(in millions)*
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:						
	Assets from risk management activities – current	**$ 24**	$ 10	Liabilities from risk management activities – current	**$ 3**	$ 28
	Other deferred charges and assets	**1**	—	Other deferred credits and liabilities	**—**	2
Total derivatives designated as hedging instruments for regulatory purposes		**$ 25**	$ 10		**$ 3**	$ 30
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Energy-related derivatives:						
	Assets from risk management activities – current	**$ 4**	$ 3	Liabilities from risk management activities – current	**$ 3**	$ 5
	Other deferred charges and assets	**—**	—	Other deferred credits and liabilities	**—**	2
Interest rate derivatives:						
	Assets from risk management activities – current	**—**	9	Liabilities from risk management activities – current	**—**	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges		**$ 4**	$ 12		**$ 3**	$ 7
Derivatives not designated as hedging instruments						
Energy-related derivatives:						
	Assets from risk management activities – current	**$ 486**	$ 741	Liabilities from risk management activities – current	**$ 482**	$ 644
	Other deferred charges and assets	**66**	179	Other deferred credits and liabilities	**81**	185
Total derivatives not designated as hedging instruments		**$ 552**	$ 920		**$ 563**	$ 829
Gross amounts of recognized assets and liabilities [(a)(b)]		**$ 581**	$ 942		**$ 569**	$ 866
Gross amounts offset in the Balance Sheet		**$ (435)**	$ (724)		**$ (497)**	$ (820)
Net amounts of derivatives assets and liabilities, presented in the Balance Sheet [(c)]		**$ 146**	$ 218		**$ 72**	$ 46

(a) The gross amounts of recognized assets and liabilities are netted on the balance sheets to the extent that there were netting arrangements with the counterparties.

(b) The gross amounts of recognized assets and liabilities do not include cash collateral held on deposit in broker margin accounts of $62 million as of December 31, 2016 and $96 million as of December 31, 2015 .

(c) As of December 31, 2016 and 2015, letters of credit from counterparties offset an immaterial portion of these assets under master netting arrangements.

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At December 31, 2016 and 2015 , 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**	
		Successor	Predecessor		**Successor**	Predecessor
Derivative Category	**Balance Sheet Location**	**December 31, 2016**	December 31, 2015	**Balance Sheet Location**	**December 31, 2016**	December 31, 2015
		(in millions)	*(in millions)*		*(in millions)*	*(in millions)*
Energy-related derivatives:						
	Other regulatory assets, current	**$ (1)**	$ (15)	Other regulatory liabilities, current	**$ 17**	$ 15
	Other regulatory assets, deferred	**—**	(2)	Other regulatory liabilities, deferred	**1**	—
Total energy-related derivative gains (losses) (*)		**$ (1)**	$ (17)		**$ 18**	$ 15

(*) Fair value gains and losses included in regulatory assets and liabilities include cash collateral held on deposit in broker margin accounts of $8 million as of December 31, 2016 and $19 million as of December 31, 2015 .

For the successor period of July 1, 2016 through December 31, 2016 and the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014 , the pre-tax effect of energy-related derivatives and interest rate derivatives designated as cash flow hedging instruments recognized in OCI and those reclassified from accumulated OCI into earnings were as follows:

	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**	
	Successor	Predecessor		**Successor**	Predecessor
Derivatives in Cash Flow Hedging Relationships	**July 1, 2016 through December 31, 2016**	**January 1, 2016 through June 30, 2016**	**Statements of Income Location**	**July 1, 2016 through December 31, 2016**	**January 1, 2016 through June 30, 2016**
	(in millions)	*(in millions)*		*(in millions)*	*(in millions)*
Energy-related derivatives	**$ 2**	**$ —**	Cost of natural gas	**$ (1)**	**$ (1)**
Interest rate derivatives	**(5)**	**(64)**	Interest expense, net of amounts capitalized	**—**	**—**
Total derivatives in cash flow hedging relationships	**$ (3)**	**$ (64)**		**$ (1)**	**$ (1)**

	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**	
	Predecessor			Predecessor	
Derivatives in Cash Flow Hedging Relationships	2015	2014	**Statements of Income Location**	2015	2014
	(in millions)			*(in millions)*	
Energy-related derivatives	$ 3	$ (8)	Cost of natural gas	$ (10)	$ 4
			Other operations and maintenance	(1)	1
Interest rate derivatives	—	—	Interest expense, net of amounts capitalized	2	—
Total derivatives in cash flow hedging relationships	$ 3	$ (8)		$ (9)	$ 5

There was no material ineffectiveness recorded in earnings for any period presented.

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For the successor period of July 1, 2016 through December 31, 2016 and the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014 , the pre-tax effects of energy-related derivatives and interest rate derivatives not designated as hedging instruments on the statements of income were as follows:

		Gain (Loss)			
		Successor	Predecessor		
		July 1, 2016 through December 31,	January 1, 2016 through June 30,	Years Ended December 31,	
Derivatives in Non-Designated Hedging Relationships	**Statements of Income Location**	**2016**	**2016**	2015	2014
		(in millions)	*(in millions)*		
Energy-related derivatives	Natural gas revenues (*)	**$ 33**	**$ (1)**	$ 56	$ 149
	Cost of natural gas	**3**	**(62)**	(6)	(7)
Total derivatives in non-designated hedging relationships		**$ 36**	**$ (63)**	$ 50	$ 142

(*) Excludes gains (losses) recorded in cost of natural gas associated with weather derivatives of $6 million for the successor periods of July 1, 2016 through December 31, 2016 and $3 million , $12 million , and $(7) million for the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014 , respectively.

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 a credit rating change below BBB- and/or Baa3. At December 31, 2016 , the Company had no collateral posted with derivative counterparties to satisfy these arrangements.

At December 31, 2016 , the fair value of derivative liabilities with contingent features was $5 million and the maximum potential collateral requirements arising from the credit-risk-related contingent features was $9 million .

Generally, collateral may be provided by a guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has 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. Prior to entering into a physical transaction, the Company assigns physical wholesale counterparties an internal credit rating and credit limit based on the counterparties' Moody's, S&P, and Fitch ratings, commercially available credit reports, and audited financial statements. The Company may require counterparties to pledge additional collateral when deemed necessary. Credit evaluations are conducted and appropriate internal approvals are obtained for a counterparty's line of credit before any transaction with the counterparty is executed. In most cases, the counterparty must have an investment grade rating, which includes a minimum long-term debt rating of Baa3 from Moody's and BBB- from S&P. Generally, the Company requires credit enhancements by way of a guaranty, cash deposit, or letter of credit for transaction counterparties that do not have investment grade ratings.

The Company also utilizes master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When the Company is engaged in more than one outstanding derivative transaction with the same counterparty and it also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of the Company's credit risk. The Company also uses other netting agreements with certain counterparties with whom it conducts significant transactions. Master netting agreements enable the Company to net certain assets and liabilities by counterparty. The Company also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions. The Company may require counterparties to pledge additional collateral when deemed necessary. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

11 . MERGER AND ACQUISITION

Merger with Southern Company

On July 1, 2016, the Company completed the Merger with Southern Company. A wholly-owned, direct subsidiary of Southern Company merged with and into Southern Company Gas, with the Company surviving as a wholly-owned, direct subsidiary of Southern Company.

At the effective time of the Merger, each share of Southern Company Gas common stock, other than certain excluded shares, was converted into the right to receive $66 in cash, without interest. Also at the effective time of the Merger, all of the outstanding restricted stock units, restricted stock awards, non-employee director stock awards, stock options, and performance share units were either redeemed or converted into Southern Company's restricted stock units. See Note 8 for additional information.

The application of the acquisition method of accounting was pushed down to the Company. The excess of the purchase price over the fair values of the Company's assets and liabilities was recorded as goodwill, which represents a different basis of accounting from the historical basis prior to the Merger. The following table presents the final purchase price allocation:

	Successor	Predecessor	
	New Basis	Old Basis	Change in Basis
	(in millions)	*(in millions)*	
Current assets	$ 1,557	$ 1,474	$ 83
Property, plant, and equipment	10,108	10,148	(40)
Goodwill	5,967	1,813	4,154
Other intangible assets	400	101	299
Regulatory assets	1,118	679	439
Other assets	229	273	(44)
Current liabilities	(2,201)	(2,205)	4
Other liabilities	(4,742)	(4,600)	(142)
Long-term debt	(4,261)	(3,709)	(552)
Contingently redeemable noncontrolling interest	(174)	(41)	(133)
Total purchase price/equity	$ 8,001	$ 3,933	$ 4,068

Measurement period adjustments were recorded to the purchase price allocation during the fourth quarter 2016, which resulted in a net $30 million increase in goodwill to establish intangible liabilities for transportation contracts at wholesale services, partially offset by adjustments to deferred tax balances.

In determining the fair value of assets and liabilities subject to rate regulation that allows recovery of costs and/or a fair return on investments, historical cost was deemed to be a reasonable proxy for fair value, as it is included in rate base or otherwise specified in regulatory recovery mechanisms. Property, plant, and equipment subject to rate regulation was reflected based on the historical gross amount of assets in service and accumulated depreciation, as they are included in rate base. For certain assets and liabilities subject to rate regulation (such as debt instruments and employee benefit obligations), the fair value adjustment was applied to historical cost with a corresponding offset to regulatory asset or liability based on the assessment of probable future recovery in rates.

For unregulated assets and liabilities, fair value adjustments were applied to historical cost of natural gas for sale, property, plant, and equipment, debt instruments, and noncontrolling interest. The valuation of other intangible assets included customer relationships, trade names, and favorable/unfavorable contracts. The valuation of these assets and liabilities applied either the market approach or income approach. The market approach was utilized when prices and other relevant market information were available. The income approach, which is based on discounted cash flows, was primarily based on significant unobservable inputs (Level 3). Key estimates and inputs included forecasted profitability and cash flows, customer retention rates, royalty rates, and discount rates.

The estimated fair value of deferred income taxes was determined by applying the appropriate enacted statutory tax rate to the temporary differences that arose on the differences between the financial reporting value and tax basis of the assets acquired and liabilities assumed.

The excess of the purchase price over the estimated fair value of assets and liabilities of $6.0 billion was recognized as goodwill, which is primarily attributable to positioning Southern Company to provide natural gas infrastructure to meet customers' growing energy needs and to compete for growth across the energy value chain. The Company anticipates that the majority of the value assigned to goodwill will not be deductible for tax purposes.

The Company's results for the successor period of July 1, 2016 through December 31, 2016 include a $20 million decrease in consolidated earnings comprised of $17 million of reduced revenues and $22 million of increased amortization, partially offset by lower interest expense of $19 million , as a result of the fair value adjustment of assets and liabilities in the application of acquisition accounting. Transaction costs included $18 million in rate credits provided to the customers of Elizabethtown Gas and Elkton Gas as a condition of the Merger, $3 million for financial advisory fees, legal expenses, and other Merger-related costs, including certain amounts payable upon successful completion of the Merger, and $20 million for additional compensation-related expenses, including accelerated vesting of share-based compensation expenses and change-in-control compensation charges.

During the predecessor period of January 1, 2016 through June 30, 2016 , the Company recorded in its statements of income transaction costs of $56 million . Transaction costs included $31 million for financial advisory fees, legal expenses, and other Merger-related costs, including certain amounts payable upon successful completion of the Merger, which was deemed probable on June 29, 2016, and $25 million of additional compensation related expenses, including accelerated vesting of share-based compensation expenses and certain Merger-related compensation charges. The Company recorded Merger-related expenses of $44 million for the predecessor year ended December 31, 2015. The Company previously treated these costs as tax deductible since the requisite closing conditions to the Merger had not yet been satisfied. During the second quarter 2016, when the Merger became probable, the Company re-evaluated the tax deductibility of these costs and reflected any non-deductible amounts in the effective tax rate.

The receipt of required regulatory approvals was conditioned upon certain terms and commitments. In connection with these regulatory approvals, certain regulatory agencies prohibited the Company from recovering goodwill and Merger-related expenses, required the Company to maintain a minimum number of employees for a set period of time to ensure that certain pipeline safety standards and the competence level of the employee workforce is not degraded, and/or required the Company to maintain its pre-Merger level of support for various social and charitable programs. The most notable terms and commitments with potential financial impacts included:

- rate credits of $18 million to be paid to customers in New Jersey and Maryland;
- sharing of Merger savings with customers in Georgia starting in 2020;
- phasing-out the use of the Nicor name or logo by certain of the Company's gas marketing services subsidiaries in conducting non-utility business in Illinois;
- reaffirming that Elizabethtown Gas would file a base rate case no later than September 1, 2016, with another base rate case no later than three years after the 2016 rate case; and
- requiring Elkton Gas to file a base rate case within two years of closing the Merger.

There is no restriction on the Company's other utilities' ability to file future rate cases. The rate credits to customers in New Jersey and Maryland were paid during the third and fourth quarters of 2016, respectively, and Elizabethtown Gas filed a base rate case with the New Jersey BPU on September 1, 2016. Upon completion of the Merger, the Company amended and restated its Bylaws and Articles of Incorporation, under which it now has the authority to issue no more than 110 million shares of stock consisting of (i) 100 million shares of common stock and (ii) 10 million shares of preferred stock, both categories of which have a par value of $0.01 per share. The amended and restated Articles of Incorporation do not allow any treasury shares to be held.

Investment in SNG

On September 1, 2016, the Company, through a wholly-owned, indirect subsidiary, acquired a 50% equity interest in SNG pursuant to a definitive agreement between Southern Company and Kinder Morgan, Inc. on July 10, 2016, to which Southern Company assigned all rights and obligations to the Company on August 31, 2016. SNG owns a 7,000 -mile pipeline system connecting natural gas supply basins in Texas, Louisiana, Mississippi, and Alabama to markets in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina, and Tennessee. The purchase price of $1.4 billion was financed by a $1.05 billion equity contribution from Southern Company and $360 million of cash paid by the Company, which was financed by a promissory note from Southern Company and repaid with a portion of the proceeds from the senior notes issued in September 2016. The purchase price of the 50% equity interest exceeded the underlying ownership interest in the net assets of SNG by approximately $700 million . This basis difference is attributable to goodwill and deferred tax assets. While the deferred tax assets will be amortized through deferred tax expense, the goodwill will not be amortized and is not required to be tested for impairment on an annual basis. See Note 4 under "Equity Method Investments" for additional information on this investment.

NOTES (continued)
Southern Company Gas and Subsidiary Companies 2016 Annual Report

12 . SEGMENT AND RELATED INFORMATION

The Company manages its business through four reportable segments - gas distribution operations (formerly referred to as distribution operations), gas marketing services (formerly referred to as retail operations), wholesale gas services (formerly referred to as wholesale services), and gas midstream operations (formerly referred to as midstream operations). The non-reportable segments are combined and presented as all other. In conjunction with the Merger, the Company changed the names of certain reportable segments to better align with its new parent company.

Gas distribution operations is the largest component of the Company's business and includes natural gas local distribution utilities that construct, manage, and maintain intrastate natural gas pipelines and gas distribution facilities in seven states. Gas marketing services includes natural gas marketing to end-use customers primarily in Georgia and Illinois. Additionally, gas marketing services provides home equipment protection products and services. Wholesale gas services provides natural gas asset management and/or related logistics services for each of the Company's utilities except Nicor Gas as well as for non-affiliated companies. Additionally, this segment engages in natural gas storage and gas pipeline arbitrage and related activities. Since the acquisition of the Company's 50% interest in SNG, gas midstream operations primarily consists of the Company's gas pipeline investments, with storage and fuel operations also aggregated into this segment. The all other column includes segments below the quantitative threshold for separate disclosure, including the subsidiaries that fall below the quantitative threshold for separate disclosure.

After the Merger, the Company changed the segment performance measure to net income, which is utilized by its new parent company. In order to properly assess net income by segment, the Company executed various intercompany note agreements to revise interest charges to its segments. Since such agreements did not exist in the predecessor periods, the Company is unable to provide the comparable net income for those periods.

Financial data for business segments for the successor period of July 1, 2016 through December 31, 2016 and for the predecessor periods of January 1, 2016 through June 30, 2016 and the years ended December 31, 2015 and 2014 were as follows:

	Gas Distribution Operations	Gas Marketing Services	Wholesale Gas Services (*)	Gas Midstream Operations	Total	All Other	Eliminations	Consolidated
				(in millions)				
Successor – July 1, 2016 through December 31, 2016								
Operating revenues	$ 1,342	$ 354	$ 24	$ 31	$ 1,751	$ 3	$ (102)	$ 1,652
Depreciation and amortization	185	35	1	9	230	8	—	238
Earnings from equity method investments	—	—	—	58	58	2	—	60
Interest expense	(105)	(1)	(3)	(16)	(125)	44	—	(81)
Income taxes	51	7	(3)	16	71	5	—	76
Segment net income (loss)	77	19	—	20	116	(2)	—	114
Gross property additions	561	5	1	54	621	11	—	632
Successor – Total assets at December 31, 2016	19,453	2,084	1,127	2,211	24,875	11,145	(14,167)	21,853

(*) The revenues for wholesale gas services are netted with costs associated with its energy and risk management activities. A reconciliation of operating revenues and intercompany revenues is shown in the following table.

NOTES (continued)
Southern Company Gas and Subsidiary Companies 2016 Annual Report

	Gas Distribution Operations	Gas Marketing Services	Wholesale Gas Services (*)	Gas Midstream Operations	Total	All Other	Eliminations	Consolidated
				(in millions)				
Predecessor – January 1, 2016 through June 30, 2016								
Operating revenues	$ 1,575	$ 435	$ (32)	$ 25	$ 2,003	$ 4	$ (102)	$ 1,905
Depreciation and amortization	178	11	1	9	199	7	—	206
EBIT	353	109	(68)	(6)	388	(60)	—	328
Gross property additions	484	4	1	43	532	16	—	548
Predecessor – Year Ended December 31, 2015								
Operating revenues	$ 3,049	$ 835	$ 202	$ 55	$ 4,141	$ 11	$ (211)	$ 3,941
Depreciation and amortization	336	25	1	18	380	17	—	397
EBIT	581	152	110	(23)	820	(59)	—	761
Gross property additions	957	7	2	27	993	34	—	1,027
Predecessor – Total assets at December 31, 2015	12,519	686	935	692	14,832	9,662	(9,740)	14,754
Predecessor – Year Ended December 31, 2014								
Operating revenues	$ 4,001	$ 994	$ 578	$ 88	5,661	$ 7	$ (283)	$ 5,385
Depreciation and amortization	317	28	1	18	364	16	—	380
EBIT	582	132	425	(17)	1,122	(10)	—	1,112
Gross property additions	715	11	2	15	743	26	—	769
Predecessor – Total assets at December 31, 2014	12,038	670	1,402	694	14,804	9,705	(9,647)	14,862

(*) The revenues for wholesale gas services are netted with costs associated with its energy and risk management activities. A reconciliation of operating revenues and intercompany revenues is shown in the following table.

	Third Party Gross Revenues	Intercompany Revenues	Total Gross Revenues	Less Gross Gas Costs	Operating Revenues
			(in millions)		
Successor – July 1, 2016 through December 31, 2016	**$ 5,807**	**$ 333**	**$ 6,140**	**$ 6,116**	**$ 24**
			(in millions)		
Predecessor – January 1, 2016 through June 30, 2016	$ 2,500	$ 143	$ 2,643	$ 2,675	$ (32)
Year Ended December 31, 2015	6,286	408	6,694	6,492	202
Year Ended December 31, 2014	10,709	718	11,427	10,849	578

13. DISCONTINUED OPERATIONS

In 2014, the Company sold Tropical Shipping, which was previously reported as its own segment, to an unrelated third party. The after-tax cash proceeds and distributions from the transaction were approximately $225 million . The Company determined that the cumulative foreign earnings of Tropical Shipping would no longer be indefinitely reinvested offshore. Accordingly, the Company recognized income tax expense of $60 million , of which $31 million was recorded in the first quarter 2014, and the remaining $29 million was recorded in the third quarter 2014 related to the cumulative foreign earnings for which no tax liabilities had been previously recorded, resulting in the repatriation of $86 million in cash.

NOTES (continued)
Southern Company Gas and Subsidiary Companies 2016 Annual Report

During 2014, based upon the negotiated sales price, the Company recorded a non-cash goodwill impairment charge of $19 million , for which there was no income tax benefit. Additionally, the Company recognized a total charge of $7 million in 2014 related to the suspension of depreciation and amortization on assets for which the Company was not compensated by the buyer.

The components of discontinued operations recorded on the statements of income for the predecessor year ended December 31, 2014 are as follows:

	Year Ended December 31, 2014
	(in millions)
Operating revenues	$ 243
Operating expenses	
Cost of goods sold	149
Operation and maintenance	75
Depreciation and amortization	5
Taxes other than income taxes	5
Loss on sale and goodwill impairment (*)	28
Total operating expenses	262
Operating (loss) income	(19)
(Loss) income before income taxes	(19)
Income tax expense	(61)
(Loss) income from discontinued operations, net of tax	$ (80)

(*) Primarily reflects $7 million due to the suspension of depreciation and amortization during 2014 and $19 million of goodwill attributable to Tropical Shipping that was impaired in 2014, based on the negotiated sales price.

NOTES (continued)
Southern Company Gas and Subsidiary Companies 2016 Annual Report

14. CAPITALIZATION

The capitalization for the years ended December 31, 2016 and 2015 are as follows:

	Successor	Predecessor	Successor	Predecessor
	2016	2015	**2016**	2015
	(in millions)	*(in millions)*	*(percent of total)*	*(percent of total)*
Long-Term Debt:				
Long-term notes payable —				
1.47% to 9.10% due 2016-2046 [(a)]	**$ 3,887**	$ 3,181		
Other long-term debt —				
First mortgage bonds —				
2.66% to 6.58% due 2016-2038 [(b)]	**625**	375		
Gas facility revenue bonds —				
Variable rate (1.28% at 1/1/17) due 2022-2033	**200**	200		
Total other long-term debt	**825**	575		
Unamortized fair value adjustment of long-term debt	**578**	68		
Unamortized debt discount	**(9)**	(4)		
Total long-term debt (annual interest requirement — $207 million)	**5,281**	3,820		
Less amount due within one year	**22**	545		
Long-term debt excluding amount due within one year	**5,259**	3,275	**36.6%**	45.2%
Common Stockholder's Equity:				
Common stock — 2016: par value $0.01 per share				
— 2015 par value $5 per share				
Authorized — 2016: 100 million shares				
— 2015: 750 million shares				
Outstanding — 2016: 100 shares				
— 2015: 120.4 million shares				
Treasury — 2016: no shares				
— 2015: 0.2 million shares				
Paid-in capital	**9,095**	2,702		
Treasury, at cost	**—**	(8)		
Retained earnings (accumulated deficit)	**(12)**	1,421		
Accumulated other comprehensive income (loss)	**26**	(186)		
Total common stockholder's equity	**9,109**	3,929	**63.4**	54.2
Noncontrolling interest	**—**	46	**—**	0.6
Total stockholders' equity	**9,109**	3,975		
Total Capitalization	**$ 14,368**	$ 7,250	**100.0%**	100.0%

(a) Long-term notes payable maturities are as follows: $22 million in 2017 (7.20%); $155 million in 2018 (3.50%); $300 million in 2019 (5.25%); $330 million in 2021 (3.50% to 9.10%); and $3.1 billion in 2022 - 2046 (2.45% to 8.70%).

(b) First mortgage bonds maturities are as follows: $50 million in 2019 (4.70%) and $575 million in 2023 - 2038 (2.66% to 6.58%).

15. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for the successor period of July 1, 2016 through December 31, 2016 and for the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 are as follows:

Quarter Ended	Operating Revenues	Operating Income (Loss)	EBIT	Net Income (Loss)
		(in millions)		
Predecessor - January 1, 2016 through June 30, 2016				
March 2016	**$ 1,334**	**$ 348**	**$ 351**	**$ 182**
June 2016	**571**	**(27)**	**(23)**	**(51)**
Successor - July 1, 2016 through December 31, 2016				
September 2016	**$ 543**	**$ 12**	**$ 50**	**$ 4**
December 2016	**1,109**	**185**	**221**	**110**
Predecessor - 2015				
March 2015	$ 1,721	$ 364	$ 367	$ 193
June 2015	674	107	111	42
September 2015	584	59	62	11
December 2015	962	216	221	107

The Company's business is influenced by seasonal weather conditions.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2012 - 2016
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	Successor	Predecessor				
	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016	2015	2014	2013	2012
Operating Revenues (in millions)	$ 1,652	$ 1,905	$ 3,941	$ 5,385	$ 4,209	$ 3,562
Income From Continuing Operations (in millions)	$ 114	$ 145	$ 373	$ 580	$ 308	$ 274
Net Income Attributable to Southern Company Gas (in millions)	$ 114	$ 131	$ 353	$ 482	$ 295	$ 260
Cash Dividends on Common Stock (in millions)	$ 126	$ 128	$ 244	$ 233	$ 222	$ 203
Return on Average Common Equity (percent)	1.74	3.31	9.05	12.96	8.42	7.77
Total Assets (in millions)	$ 21,853	$ 14,488	$ 14,754	$ 14,888	$ 14,528	$ 14,051
Gross Property Additions (in millions)	$ 632	$ 548	$ 1,027	$ 769	$ 731	$ 775
Capitalization (in millions):						
Common stock equity	$ 9,109	$ 3,933	$ 3,975	$ 3,828	$ 3,613	$ 3,391
Long-term debt	5,259	3,709	3,275	3,581	3,791	3,307
Total (excluding amounts due within one year)	$ 14,368	$ 7,642	$ 7,250	$ 7,409	$ 7,404	$ 6,698
Capitalization Ratios (percent):						
Common stock equity	63.4	51.5	54.8	51.7	48.8	50.6
Long-term debt	36.6	48.5	45.2	48.3	51.2	49.4
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0	100.0
Service Contracts (year-end)	1,198,263	1,197,096	1,205,476	1,162,065	1,176,908	673,506
Customers (year-end)						
Gas distribution operations	4,586,477	4,544,489	4,557,729	4,529,114	4,504,067	4,477,986
Gas marketing services	655,999	630,475	654,475	633,460	632,337	608,711
Total (year-end)	5,242,476	5,174,964	5,212,204	5,162,574	5,136,404	5,086,697
Employees (year-end)	5,292	5,284	5,203	5,165	6,094	6,121

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2012 - 2016 (continued)
Southern Company Gas and Subsidiary Companies 2016 Annual Report

	Successor	Predecessor				
	July 1, 2016 through December 31, 2016	**January 1, 2016 through June 30, 2016**	**2015**	**2014**	**2013**	**2012**
Operating Revenues (in millions)						
Residential	**$ 899**	**$ 1,101**	$ 2,129	$ 2,877	$ 2,422	$ 2,011
Commercial	**260**	**310**	617	861	696	656
Transportation	**269**	**290**	526	458	487	474
Industrial	**74**	**72**	203	242	180	262
Other	**150**	**132**	466	947	424	159
Total	**$ 1,652**	**$ 1,905**	$ 3,941	$ 5,385	$ 4,209	$ 3,562
Heating Degree Days:						
Illinois	**1,903**	**3,340**	5,433	6,556	6,305	4,863
Georgia	**727**	**1,448**	2,204	2,882	2,689	1,934
Gas Sales Volumes (mmBtu in millions):						
Gas distributions operations						
Firm	**274**	**396**	695	766	720	606
Interruptible	**47**	**49**	99	106	111	107
Total	**321**	**445**	794	872	831	713
Gas marketing services						
Firm:						
Georgia	**13**	**21**	35	41	38	31
Illinois	**4**	**8**	13	17	9	8
Other emerging markets	**5**	**7**	11	10	8	8
Interruptible (large commercial and industrial)	**6**	**8**	14	17	18	17
Total	**28**	**44**	73	85	73	64
Market share in Georgia (percent)	**29.4**	**29.3**	29.7	30.6	31.4	32.1
Wholesale gas services						
Daily physical sales (*mmBtu in millions/day*)	**7.2**	**7.6**	6.8	6.3	5.7	5.5

PART III

Items 10, 11, 12 (other than the information under "Code of Ethics" below in Item 10), 13, and 14 for Southern Company are incorporated by reference to Southern Company's Definitive Proxy Statement relating to the 2017 Annual Meeting of Stockholders. Specifically, reference is made to "Corporate Governance at Southern Company" and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Compensation Discussion and Analysis," "Executive Compensation Tables," and "Director Compensation" for Item 11, "Stock Ownership Information" and "Executive Compensation Tables" for Item 12, "Southern Company Board" for Item 13, and "Principal Independent Registered Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12 (other than the information under "Code of Ethics" below in Item 10), 13, and 14 for Alabama Power, Georgia Power, and Mississippi Power are incorporated by reference to the Definitive Information Statements of Alabama Power, Georgia Power, and Mississippi Power relating to each of their respective 2017 Annual Meetings of Shareholders. Specifically, reference is made to "Nominees for Election as Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation," "Compensation Committee Interlocks and Insider Participation," "Director Compensation," "Director Deferred Compensation Plan," and "Director Compensation Table" for Item 11, "Stock Ownership Table" and "Executive Compensation" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal Independent Registered Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12, 13, and 14 for Gulf Power are contained herein.

Items 10, 11, 12, and 13 for each of Southern Power and Southern Company Gas are omitted pursuant to General Instruction I(2)(c) of Form 10-K. Item 14 for each of Southern Power and Southern Company Gas is contained herein.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Identification of directors of Gulf Power **(1)**

S. W. Connally, Jr. Chairman, President, and Chief Executive Officer Age 47 Served as Director since 2012	**Julian B. MacQueen (2)** Age 66 Served as Director since 2013
Allan G. Bense (2) Age 65 Served as Director since 2010	**J. Mort O'Sullivan, III (2)** Age 65 Served as Director since 2010
Deborah H. Calder (2) Age 56 Served as Director since 2010	**Michael T. Rehwinkel (2)** Age 60 Served as Director since 2013
William C. Cramer, Jr. (2) Age 64 Served as Director since 2002	**Winston E. Scott (2)** Age 66 Served as Director since 2003

(1) *Ages listed are as of December 31, 2016.*
(2) *No position other than director.*

Each of the above is currently a director of Gulf Power, serving a term running from the last annual meeting of Gulf Power's shareholders (June 28, 2016) for one year until the next annual meeting or until a successor is elected and qualified.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as a director, other than any arrangements or understandings with directors or officers of Gulf Power acting solely in their capacities as such.

Identification of executive officers of Gulf Power **(1)**

S. W. Connally, Jr. Chairman, President, and Chief Executive Officer Age 47 Served as Executive Officer since 2012	**Michael L. Burroughs** Vice President — Senior Production Officer Age 56 Served as Executive Officer since 2010
Jim R. Fletcher Vice President — External Affairs and Corporate Services Age 50 Served as Executive Officer since 2014	**Wendell E. Smith** Vice President — Power Delivery Age 51 Served as Executive Officer since 2014
Xia Liu Vice President and Chief Financial Officer Age 46 Served as Executive Officer since 2015	**Bentina C. Terry** Vice President — Customer Service and Sales Age 46 Served as Executive Officer since 2007

(1) *Ages listed are as of December 31, 2016.*

Each of the above is currently an executive officer of Gulf Power, serving a term until the next annual organizational meeting of the Board of Directors or until a successor is elected and qualified.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as an officer, other than any arrangements or understandings with directors or officers of Gulf Power acting solely in their capacities as such.

Identification of certain significant employees. *None.*

Family relationships. *None.*

Business experience. *Unless noted otherwise, each director has served in his or her present position for at least the past five years.*

DIRECTORS

Gulf Power's Board of Directors possesses collective knowledge and experience in accounting, finance, leadership, business operations, risk management, corporate governance, and Gulf Power's industry.

S. W. Connally, Jr. - Mr. Connally has served as President, Chief Executive Officer, and Director of Gulf Power since July 2012. He has served as Chairman of Gulf Power's Board of Directors since July 2012 and was first elected to that position in July 2015. Mr. Connally previously served as Senior Vice President and Chief Production Officer of Georgia Power from August 2010 through June 2012. He has been a member of the board of directors of Capital City Bank Group, Inc. since January 2017.

Allan G. Bense - Panama City businessman and former Speaker of the Florida House of Representatives. Mr. Bense is a partner in several companies involved in road building, mechanical contracting, insurance, general contracting, golf courses, and farming. He has more than 43 years of business and leadership experience. Mr. Bense also has been a member of the board of directors of Capital City Bank Group, Inc. since 2013.

Deborah H. Calder - Executive Vice President for Navy Federal Credit Union since 2014. From 2008 to 2014, she served as Senior Vice President. Ms. Calder directs the day-to-day operations of more than 5,000 employees and the ongoing construction of Navy Federal Credit Union's campus in the Pensacola area. Ms. Calder has been with Navy Federal Credit Union for over 25 years, serving in previous positions as Vice President of Consumer and Credit Card Lending, Vice President of Collections, Vice President of Call Center Operations, and Assistant Vice President of Credit Cards.

William C. Cramer, Jr. - President and Owner of automobile dealerships in Florida and Alabama. Mr. Cramer has been an authorized Chevrolet dealer for over 27 years. In 2009, Mr. Cramer became an authorized dealer of Cadillac, Buick, and GMC vehicles.

Julian B. MacQueen - Founder and Chief Executive Officer of Innisfree Hotels, Inc. for over 30 years. He is currently a member of the American Hotel & Lodging Association and a director of the Beach Community Bank.

J. Mort O'Sullivan, III - Managing Member of the Gulf Coast region of Warren Averett, LLC, a CPA and Advisory firm. Mr. O'Sullivan currently focuses on consulting and management advisory services to clients, while continuing to offer his expertise in litigation support, business valuations, and mergers and acquisitions. He is a registered investment advisor. Mr. O'Sullivan has over 35 years of leadership experience in public accounting.

Michael T. Rehwinkel - Mr. Rehwinkel previously served as Executive Chairman of EVRAZ North America, a steel manufacturer, from July 2013 to December 2015 and as Chief Executive Officer and President from February 2010 to July

2013. Mr. Rehwinkel also served as Chairman of the American Iron and Steel Institute in 2012 and 2013. Mr. Rehwinkel has more than 35 years of industrial business and leadership experience.

Winston E. Scott - Senior Advisor to the President, Florida Institute of Technology since January 2017. Mr. Scott previously served as Senior Vice President for External Relations and Economic Development, Florida Institute of Technology from March 2012 to January 2017 and Dean, College of Aeronautics, Florida Institute of Technology from August 2008 through March 2012. Mr. Scott is also a member of the board of directors of Environmental Tectonics Corporation.

EXECUTIVE OFFICERS

Michael L. Burroughs - Vice President and Senior Production Officer since August 2010.

Jim R. Fletcher - Vice President of External Affairs and Corporate Services since March 2014. He previously served as Vice President of Governmental and Regulatory Affairs for Georgia Power from January 2011 to February 2014.

Xia Liu - Vice President and Chief Financial Officer since June 2015. She previously served as Treasurer of Southern Company and Senior Vice President of Finance and Treasurer of SCS from March 2014 to June 2015 and Assistant Treasurer of Southern Company and Vice President of Finance and Assistant Treasurer of SCS from July 2010 to March 2014.

Wendell E. Smith - Vice President of Power Delivery since March 2014. He previously served as the General Manager of Distribution Engineering, Construction and Maintenance and Distribution Operations Systems for Georgia Power from January 2012 to February 2014.

Bentina C. Terry - Vice President of Customer Service and Sales since March 2014. She previously served as Vice President of External Affairs and Corporate Services from March 2007 to March 2014.

Involvement in certain legal proceedings. None.

Promoters and Control Persons. None.

Section 16(a) Beneficial Ownership Reporting Compliance. No late filings to report.

Code of Ethics

The registrants collectively have adopted a code of business conduct and ethics (Code of Ethics) that applies to each director, officer, and employee of the registrants and their subsidiaries. The Code of Ethics can be found on Southern Company's website located at www.southerncompany.com. The Code of Ethics is also available free of charge in print to any shareholder by requesting a copy from Myra C. Bierria, Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308. Any amendment to or waiver from the Code of Ethics that applies to executive officers and directors will be posted on the website.

Corporate Governance

Southern Company has adopted corporate governance guidelines and committee charters. The corporate governance guidelines and the charters of Southern Company's Audit Committee, Compensation and Management Succession Committee, Finance Committee, Governance Committee, and Nuclear/Operations Committee can be found on Southern Company's website located at www.southerncompany.com. The corporate governance guidelines and charters are also available free of charge in print to any shareholder by requesting a copy from Myra C. Bierria, Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308.

Southern Company owns all of Gulf Power's outstanding common stock. Under the rules of the SEC, Gulf Power is exempt from the audit committee requirements of Section 301 of the Sarbanes-Oxley Act of 2002 and, therefore, is not required to have an audit committee or an audit committee report on whether it has an audit committee financial expert.

Item 11. EXECUTIVE COMPENSATION

GULF POWER

COMPENSATION DISCUSSION AND ANALYSIS (CD&A)

In this CD&A and this Form 10-K, references to the "Compensation Committee" are to the Compensation and Management Succession Committee of the Board of Directors of Southern Company.

This section describes the compensation program for Gulf Power's Chief Executive Officer and Chief Financial Officer in 2016, as well as each of its other three most highly compensated executive officers serving at the end of the year. Collectively, these officers are referred to as the named executive officers.

S. W. Connally, Jr.	Chairman, President, and Chief Executive Officer
Xia Liu	Vice President and Chief Financial Officer
Jim R. Fletcher	Vice President
Wendell E. Smith	Vice President
Bentina C. Terry	Vice President

EXECUTIVE SUMMARY

Pay for Performance

Performance-based pay represents a substantial portion of the total direct compensation paid or granted to the named executive officers for 2016.

	Salary ($) (1)	% of Total	Annual Cash Incentive Award ($) (2)	% of Total	Long-term Equity Incentive Award ($) (3)	% of Total
S. W. Connally, Jr.	453,521	26%	510,624	29%	805,355	45%
X. Liu	281,309	42%	220,461	33%	169,904	25%
J. R. Fletcher	252,461	42%	202,464	33%	148,596	25%
W. E. Smith	218,707	48%	158,447	34%	84,719	18%
B. C. Terry	284,498	42%	219,620	32%	173,191	26%

(1) Salary is the actual amount paid in 2016.
(2) Annual Cash Incentive Award is the actual amount earned in 2016 under the Performance Pay Program based on achievement of annual performance goals.
(3) Long-Term Equity Incentive Award reflects the target value of the performance shares granted in 2016 under the Performance Share Program.

The executive compensation program places significant focus on rewarding performance. The program is performance-based in several respects:

- Business unit financial and operational performance and Southern Company earnings per share (EPS), based on actual results as adjusted by the Compensation Committee, compared to target performance levels established early in the year, determine the actual payouts under the annual cash incentive award program (Performance Pay Program).

- Southern Company's total shareholder return (TSR) compared to those of industry peers, cumulative EPS, and equity-weighted return on equity (ROE) over a three-year period lead to higher or lower payouts under the long-term equity incentive award program (Performance Share Program).

In support of this performance-based pay philosophy, Gulf Power has no general employment contracts with the named executive officers.

The pay-for-performance principles apply not only to the named executive officers but to hundreds of Gulf Power's employees. The Performance Pay Program covers almost all of the approximately 1,400 employees of Gulf Power. Performance shares were granted to 133 employees of Gulf Power in 2016. These programs engage employees and encourage alignment of their interests with Gulf Power's customers and Southern Company's stockholders.

Gulf Power's financial and operational goal results and Southern Company's EPS goal results for 2016, as adjusted and further described in this CD&A, are shown below:

Financial: 187% of Target Operational: 161% of Target EPS: 171% of Target

Southern Company's annualized TSR has been:

1-Year: 9.9% 3-Year: 11.2% 5-year: 5.9%

These levels of achievement, as adjusted, resulted in payouts that were aligned with Gulf Power's and Southern Company's performance**.**

Compensation Philosophy

Gulf Power's compensation program is based on the following beliefs:

- Employees' commitment and performance have a significant impact on achieving business results;
- Compensation and benefits offered must attract, retain, and engage employees and must be financially sustainable;
- Compensation should be consistent with performance: higher pay for higher performance and lower pay for lower performance; and
- Both business drivers and culture should influence the compensation and benefit program.

Based on these beliefs, the Compensation Committee believes that Gulf Power's executive compensation program should:

- Be competitive with Gulf Power's industry peers;
- Reward achievement of Gulf Power's goals;
- Be aligned with the interests of Southern Company's stockholders and Gulf Power's customers; and
- Not encourage excessive risk-taking.

Executive compensation is targeted at the market median of industry peers, but actual compensation is primarily determined by achievement of Gulf Power's and Southern Company's business goals. Gulf Power believes that focusing on the customer drives achievement of financial objectives and delivery of a premium, risk-adjusted TSR for Southern Company's stockholders. Therefore, short-term performance pay is based on achievement of Gulf Power's operational and financial performance goals and Southern Company's EPS goal. Long-term performance pay is tied to Southern Company's TSR performance, cumulative EPS, and equity-weighted ROE .

Key Compensation Practices

- Annual pay risk assessment required by the Compensation Committee charter.
- Retention by the Compensation Committee of an independent compensation consultant, Pay Governance LLC (Pay Governance), that provides no other services to Gulf Power or Southern Company.
- Inclusion of a claw-back provision that permits the Compensation Committee to recoup performance pay from any employee if determined to have been based on erroneous results, and requires recoupment from an executive officer in the event of a material financial restatement due to fraud or misconduct of the executive officer.
- No excise tax gross-up on change-in-control severance arrangements.
- Provision of limited perquisites with no income tax gross-ups for the Chairman, President, and Chief Executive Officer, except on certain relocation-related benefits.
- "No-hedging" provision in Gulf Power's insider trading policy that is applicable to all employees.
- Policy against pledging of Southern Company stock applicable to all executive officers and directors of Southern Company, including Gulf Power's Chief Executive Officer.
- Strong stock ownership requirements that are being met by all named executive officers.

Establishing Executive Compensation

The Compensation Committee establishes the Southern Company system executive compensation program. In doing so, the Compensation Committee relies on input from its independent compensation consultant, Pay Governance. The Compensation Committee also relies on input from the Southern Company Human Resources staff and, for individual executive officer performance, from Southern Company's and Gulf Power's respective Chief Executive Officers. The role and information provided by each of these sources is described throughout this CD&A.

Consideration of Southern Company Stockholder Advisory Vote on Executive Compensation

The Compensation Committee considered the stockholder vote on Southern Company's executive compensation at the Southern Company 2016 annual meeting of stockholders. In light of the significant support of Southern Company's stockholders (93% of votes cast voting in favor of the proposal) and the actual payout levels of the performance-based compensation program, the Compensation Committee continues to believe that the executive compensation program is competitive, aligned with Gulf Power's and Southern Company's financial and operational performance, and in the best interests of Gulf Power's customers and Southern Company's stockholders.

ESTABLISHING MARKET-BASED COMPENSATION LEVELS

Pay Governance develops and presents to the Compensation Committee a competitive market-based compensation level for Gulf Power's Chief Executive Officer, while the Southern Company Human Resources staff develops competitive market-based compensation levels for the other Gulf Power named executive officers. The market-based compensation levels for Gulf Power's Chief Executive Officer are developed from the Willis Towers Watson Energy Services Survey focusing on regulated utilities with revenues above $6 billion, listed below. The market-based compensation levels for the other Gulf Power named executive officers are developed from a size-appropriate energy services executive compensation survey database comprised of several general industry and utility national surveys. For 2016, these levels were market tested using the Willis Towers Watson 2016 CDB Energy Services Executive Compensation Survey Report. The survey participants, listed below, are utilities with revenues of $1 billion or more.

Market data for Gulf Power's Chief Executive Officer position and other positions in terms of scope of responsibilities that most closely resemble the positions held by the named executive officers is reviewed. When appropriate, the market data is size-adjusted, up or down, to accurately reflect comparable scopes of responsibilities. Based on that data, a total target compensation opportunity is established for each named executive officer. Total target compensation opportunity is the sum of base salary, the annual cash incentive award at target performance level, and the long-term equity incentive award at target performance level. Actual compensation paid may be more or less than the total target compensation opportunity based on actual performance above or below target performance levels. As a result, the compensation program is designed to result in payouts that are market-appropriate given Gulf Power's and Southern Company's performance for the year or period.

A specified weight was not targeted for base salary, the annual cash incentive award, or the long-term equity incentive award as a percentage of total target compensation opportunities, nor did amounts realized or realizable from prior compensation serve to increase or decrease 2016 compensation amounts.

Total target compensation opportunities for senior management as a group, including the named executive officers, are managed to be at the median of the market for companies of similar size in the electric utility industry. Therefore, some executives may be paid above and others below market. This practice allows for differentiation based on time in the position, scope of responsibilities, and individual performance. The differences in the total pay opportunities for each named executive officer are based almost exclusively on the differences indicated by the market data for persons holding similar positions. Because of the use of market data from a large number of industry peer companies for positions that are not identical in terms of scope of responsibility from company to company, differences are not considered to be material and the compensation program is believed to be market-appropriate, as long as senior management as a group is within an appropriate range. Generally, compensation is considered to be within an appropriate range if it is not more or less than 15% of the applicable market data.

Gulf Power Chief Executive Officer Compensation Peer Group

American Electric Power Company, Inc.	Duke Energy Corporation	NRG Energy, Inc.
Ameren Corporation	Edison International	PG&E Corporation
Berkshire Hathaway Energy Company	Energy Transfer Partners, L.P.	PPL Corporation
Calpine Corporation	Entergy Corporation	Public Service Enterprise Group, Inc.
CenterPoint Energy, Inc.	Exelon Corporation	Sempra Energy
CMS Energy Corporation	FirstEnergy Corp.	Tennessee Valley Authority
Consolidated Edison, Inc.	Kinder Morgan, Inc.	The AES Corporation
Direct Energy	Monroe Energy LLC	The Williams Companies
Dominion Resources, Inc.	NextEra Energy, Inc.	UGI Corporation
DTE Energy Company	NiSource Inc.	Xcel Energy

Gulf Power Named Executive Officer Peer Group (non-Chief Executive Officer)

AGL Resources Inc.	Exelon Corporation	PNM Resources Inc.
Allete, Inc.	FirstEnergy Corp.	Portland General Electric Company
Alliant Energy Corporation	First Solar Inc.	PPL Corporation
Ameren Corporation	GE Energy	Public Service Enterprise Group Inc.
American Electric Power Company, Inc.	GE Oil & Gas	Puget Sound Energy, Inc.
American Water Works Company, Inc.	Genesis Energy	Questar Corporation
Areva Inc.	Idaho Power Company	Sacramento Municipal Utility District
Atmos Energy Corporation	ITC Holdings	Salt River Project
Avista Corporation	JEA	SCANA Corporation
Black Hills Corporation	Kinder Morgan Energy Partners, L.P.	ShawCor Ltd.
Boardwalk Pipeline Partners, L.P.	LG&E and KU Energy LLC	Sempra Energy
Bonneville Power Administration	Lower Colorado River Authority	Southwest Gas Corporation
Calpine Corporation	MDU Resources Group, Inc.	Spectra Energy Corp.
CenterPoint Energy, Inc.	Monroe Energy	Talen Energy
Cleco Corporation	National Grid USA	TECO Energy, Inc.
CMS Energy Corporation	New York Power Authority	Tennessee Valley Authority
Covanta Corporation	NextEra Energy, Inc.	The AES Corporation
CPS Energy	NorthWestern Corporation	The Williams Companies, Inc.
Direct Energy	NOVA Chemicals Corporation	TransCanada Corporation
Dominion Resources, Inc.	NRG Energy, Inc.	Tri-State Generation & Transmission Association, Inc.
DTE Energy Company	OGE Energy Corp.	
Duke Energy Corporation	Oglethorpe Power Corporation	UGI Corporation
Edison International	Old Dominion Electric	UIL Holdings
Enable Midstream Partners	Omaha Public Power District	UNS Energy Corporation
Energy Future Holdings Corp.	Oncor Electric Delivery Company LLC	Vectren Corporation
Energy Transfer Partners, L.P.	ONE Gas, Inc.	Westar Energy, Inc.
EnLink Midstream	ONEOK, Inc.	WEC Energy Group, Inc.
Entergy Corporation	Pacific Gas & Electric Company	Xcel Energy Inc.
EQT Corporation	Pinnacle West Capital Corporation	

EXECUTIVE COMPENSATION PROGRAM

The primary components of the 2016 executive compensation program include:

- Short-term compensation
    - Base salary
    - Performance Pay Program
- Long-term compensation
    - Performance Share Program
- Benefits

The performance-based compensation components are linked to Gulf Power's financial and operational performance as well as Southern Company's financial and stock price performance, including TSR, EPS, and ROE. The executive compensation program is approved by the Compensation Committee, which consists entirely of independent directors of Southern Company. The Compensation Committee believes that the executive compensation program is a balanced program that provides market-based compensation and rewards performance.

2016 Base Salary

Most employees, including all of the named executive officers, received base salary increases in 2016.

With the exception of Southern Company executive officers, including Mr. Connally, base salaries for all Southern Company system officers are within a position level with a base salary range that is established by Southern Company Human Resources staff using the market data described above. Each officer is within one of these established position levels based on the scope of responsibilities that most closely resemble the positions included in the market data described above. The base salary level for individual officers is set within the applicable pre-established range. Factors that influence the specific base salary level within the range include the need to retain an experienced team, internal equity, time in position, and individual performance. Individual performance includes the degree of competence and initiative exhibited and the individual's relative contribution to the achievement of financial and operational goals in prior years.

Base salaries are reviewed annually in February, and changes are made effective March 1. The 2016 base salary levels for the named executive officers, other than for the Chief Executive Officer, were set within the applicable position level salary range and approved by Gulf Power's Chief Executive Officer. Mr. Connally's base salary was recommended by the Chief Executive Officer of Southern Company and approved by the Compensation Committee.

	March 1, 2015 Base Salary ($)	March 1, 2016 Base Salary ($)
S. W. Connally, Jr.	426,119	460,208
X. Liu	258,124	283,188
J. R. Fletcher	240,470	247,684
W. E. Smith	204,555	211,715
B. C. Terry	280,264	288,672

In 2016, Mr. Fletcher and Mr. Smith received mid-year salary increases. Mr. Fletcher's salary was adjusted to $260,068, and Mr. Smith's salary was adjusted to $228,970. Mr. Fletcher's salary was adjusted to better align his compensation with that of his peers. Mr. Smith's salary was also adjusted to better align with that of his peers as well as to reflect his additional duties at Southern Company subsidiary PowerSecure. Ms. Terry's 2016 salary was adjusted after the March 1 increase to $282,108 pursuant to the Southern Company Club Dues Guidelines (Guidelines). The Guidelines detail the Southern Company system's treatment of expenses and dues related to business dining clubs and country clubs.

2016 Performance-Based Compensation

This section describes short-term and long-term performance-based compensation for 2016.

Achieving Operational and Financial Performance Goals - The Guiding Principle for Performance-Based Compensation

The Southern Company system's number one priority is to provide customers outstanding reliability and superior service at reasonable prices while achieving a level of financial performance that benefits Southern Company's stockholders in the short and

long term. Operational excellence and business unit and Southern Company financial performance are integral to the achievement of business results that benefit customers and stockholders.

Therefore, in 2016, Gulf Power strove for and rewarded:

- Continuing industry-leading reliability and customer satisfaction, while maintaining reasonable retail prices;
- Meeting energy demand with the best economic and environmental choices;
- Long-term, risk-adjusted Southern Company relative TSR performance against a group of peer companies;
- Achieving net income goals to support the Southern Company financial plan and dividend growth; and
- Financial integrity - an attractive risk-adjusted return and sound financial policy.

The performance-based compensation program is designed to encourage achievement of these goals.

2016 Annual Performance-Based Pay Program

Annual Performance Pay Program Highlights

- Rewards achievement of annual performance goals; performance results can range from 0 to 200% of target, based on actual level of goal achievement
  - EPS: earned at 171% of target
  - Net Income: earned at 187% of target
  - Operations: earned at 161% of target
- 2016 Payout: Exceeded target performance
  - Chief Executive Officer payout at 171% of target
  - Other named executive officers' payouts at 173% of target

Overview of Program Design

Almost all employees of Gulf Power, including the named executive officers, are participants.

The performance goals are set at the beginning of each year by the Compensation Committee and include financial and operational goals for all employees. In setting goals, the Compensation Committee relies on information on financial and operational goals from the Finance Committee and the Nuclear/Operations Committee of the Southern Company Board of Directors, respectively.

- **Business Unit Financial Goal: Net Income**
  For Southern Company's traditional electric operating companies, including Gulf Power, the business unit financial performance goal is net income.

- **Business Unit Operational Goals: Varies by business unit**
  For Southern Company's traditional electric operating companies, including Gulf Power, operational goals are customer satisfaction, safety, culture, transmission and distribution system reliability, plant availability, and major projects (if applicable to the specific traditional electric operating company). Each of these operational goals is explained in more detail under Goal Details below. The level of achievement for each operational goal is determined according to the respective performance schedule, and the total operational goal performance is determined by the weighted average result. Each business unit has its own operational goals.

- **Southern Company Financial Goal: EPS**
  EPS is defined as Southern Company's net income from ongoing business activities divided by average shares outstanding during the year, as adjusted and approved by the Compensation Committee. The EPS performance measure is applicable to all participants in the Performance Pay Program.

- **Individual Performance Goals for the Chief Executive Officer**
  The Performance Pay Program incorporates individual goals for all executive officers of Southern Company, including Mr. Connally. The Chief Executive Officer of Southern Company reviews the individual performance of Mr. Connally and recommends the payout level for approval by the Compensation Committee. The individual goals account for 10% of Mr. Connally's Performance Pay Program goals.

Under the terms of the program, no payout can be made if events occur that impact Southern Company's financial ability to fund the Southern Company common stock (Common Stock) dividend.

Goal Details

Operational Goals	Description	Why It Is Important
Customer Satisfaction	Customer satisfaction surveys evaluate performance. The survey results provide an overall ranking for each traditional electric operating company, including Gulf Power, as well as a ranking for each customer segment: residential, commercial, and industrial.	Customer satisfaction is key to operations. Performance of all operational goals affects customer satisfaction.
Safety	Southern Company's Target Zero program is focused on continuous improvement in striving for a safe work environment. The performance is measured by the applicable company's ranking, as compared to peer utilities in the Southeastern Electric Exchange.	Essential for the protection of employees, customers, and communities.
Culture	The culture goal seeks to improve Gulf Power's inclusive workplace. This goal includes measures for work environment (employee satisfaction survey), representation of minorities and females in leadership roles (subjectively assessed), and supplier diversity.	Supports workforce development efforts and helps to assure diversity of suppliers.
Reliability	Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on recent historical performance.	Reliably delivering power to customers is essential to Gulf Power's operations.
Availability	Peak season equivalent forced outage rate is an indicator of availability and efficient generation fleet operations during the months when generation needs are greatest. Availability is measured as a percentage of the hours of forced outages out of the total generation hours.	Availability of sufficient power during peak season fulfills the obligation to serve and provide customers with the least cost generating resources.

Financial Performance Goals	Description	Why It Is Important
EPS	Southern Company's net income from ongoing business activities divided by average shares outstanding during the year.	Supports commitment to provide Southern Company's stockholders solid, risk-adjusted returns and to support and grow the dividend.
Net Income	For the traditional electric operating companies, including Gulf Power, the business unit financial performance goal is net income after dividends on preferred and preference stock. Overall corporate performance is determined by the equity-weighted average of the business unit net income goal payouts.	Supports delivery of Southern Company stockholder value and contributes to Gulf Power's and Southern Company's sound financial policies and stable credit ratings.

Individual Performance Goals (Mr. Connally only)	Description	Why It Is Important
Individual Factors	Focus on overall business performance as well as factors including leadership development, succession planning, and fostering the culture and diversity of the organization.	Individual goals provide the Compensation Committee the ability to balance quantitative results with qualitative inputs by focusing on both business performance and behavioral aspects of leadership that lead to sustainable long-term growth.

The Compensation Committee approves threshold, target, and maximum performance levels for each of the operational goals. The ranges for the net income goal for Gulf Power and the Southern Company EPS goal for 2016 are shown below. If goal achievement is below threshold, there is no payout associated with the applicable goal.

Level of Performance	Gulf Power Net Income ($, in millions)	Southern Company EPS ($)
Maximum	132.4	2.96
Target	118.8	2.82
Threshold	105.1	2.68

Calculating Payouts

All of the named executive officers are paid based on Southern Company EPS performance as well as Gulf Power's net income and operational performance.

2016 goal achievement is shown in the following tables.

Gulf Power Operational Goal Results

Goal	Achievement
Customer Satisfaction	Maximum
Safety	Below target
Culture	Above target
Reliability	Significantly above target
Availability	Maximum
Total Gulf Power Operational Goal Performance Factor	161%

Financial Performance Goal Results

Goal	Result	Achievement Percentage (%)
Gulf Power Net Income (in millions)*	$130.7	187
Southern Company EPS (from ongoing business activities)*	$2.89	171

*The Compensation Committee may make adjustments, both positive and negative, to goal achievement for purposes of determining payouts.

- *EPS:* Southern Company's adjusted EPS result was $2.89, exceeding the $2.82 target. The adjusted EPS result excludes the impact of charges related to the Kemper IGCC, equity return related to the Kemper IGCC schedule extension, and earnings, acquisition costs, integration costs, and financing costs related to Southern Company Gas, PowerSecure, and Southern Natural Gas. This is consistent with the earnings results publicly communicated to investors.
- *Net Income:* Gulf Power's adjusted net income result was $130.7 million, exceeding the $118.8 million target. The adjusted result excludes the impact of integration costs.

A total performance factor for the named executive officers is determined by adding the applicable business unit financial and operational goal performance results and the EPS result and dividing by three, except for Mr. Connally. For Mr. Connally, the business unit financial and operational goal performance results and the EPS result are worth 30% each of the total performance factor, while his individual performance goal result is worth the remaining 10%. The total performance factor is multiplied by the target Performance Pay Program opportunity to determine the payout for each named executive officer.

	Southern Company EPS Result (%)	Business Unit Financial Goal Result (%)	Business Unit Operational Goal Result (%)	Individual Goal Result (%)	Total Performance Factor (%)
S. W. Connally, Jr.	171	187	161	150	171
X. Liu	171	187	161	N/A	173
J. R. Fletcher	171	187	161	N/A	173
W. E. Smith	171	187	161	N/A	173
B. C. Terry	171	187	161	N/A	173

	Target Annual Performance Pay Program Opportunity (% of base salary)	Target Annual Performance Pay Program Opportunity ($)	Total Performance Factor (% of target)	Actual Annual Performance Pay Program Payout ($)
S. W. Connally, Jr.	65	299,135	171	510,624
X. Liu	45	127,434	173	220,461
J. R. Fletcher	45	117,031	173	202,464
W. E. Smith	40	91,588	173	158,447
B. C. Terry	45	126,948	173	219,620

Long-Term Performance-Based Compensation

2016 Long-Term Pay Program Highlights

- Long-term performance-based awards are intended to promote long-term success and increase stockholder value by directly tying a substantial portion of the named executive officers' total compensation to the interests of Southern Company stockholders.
- Performance shares represent 100% of long-term target value
  - TSR relative to industry peers (50%)
  - Cumulative three-year EPS (25%)
  - Equity-weighted ROE (25%)
- Three-year performance period from 2016 through 2018
- Performance results can range from 0 to 200% of target
- Paid in Common Stock at the end of the performance period; accrued dividends only received if and when award is earned

2016-2018 Performance Share Program Grant

Performance shares are denominated in units, meaning no actual shares are issued on the grant date. A grant date fair value per unit was determined. For the portion of the grant attributable to the relative TSR goal, the value per unit was $45.19. For the portion of the grant attributable to the cumulative three-year EPS and equity-weighted ROE goals, the value per unit was $48.82. A target number of performance shares are granted to a participant, based on the total target value as determined as a percentage of a participant's base salary, which varies by grade level. The total target value for performance share units is divided by the value per unit to determine the number of performance share units granted to each participant, including the named executive officers. Each performance share unit represents one share of Common Stock.

The award includes three performance measures for the 2016 - 2018 performance period, as well as a credit quality threshold requirement.

Goal	What it Measures	Why it's Important
Relative TSR (50% weighting)	Total shareholder return relative to peer companies	Aligns employee pay with investor returns relative to peers
Cumulative EPS (25% weighting)	Cumulative EPS over the three-year performance period	Aligns employee pay with Southern Company's earnings growth
Equity-Weighted ROE (25% weighting)	Equity-weighted ROE of the traditional electric operating companies	Aligns employee pay with Southern Company's ability to maximize return on capital invested

The EPS and ROE goals are also both subject to a credit quality threshold requirement that encourages the maintenance of adequate credit ratings to provide an attractive return to investors. If the primary credit rating of Southern Company, Alabama Power, or Georgia Power falls below investment grade at the end of the three-year performance period, the payout for the EPS and ROE goals will be reduced to zero.

For each of the performance measures, a threshold, target, and maximum goal was set at the beginning of the performance period.

	Relative TSR Performance (50% weighting)	Cumulative EPS Performance (25% weighting)	Equity-Weighted ROE Performance (25% weighting)	Payout (% of Performance Share Units Paid)
Maximum	90th percentile or higher	$9.37	6.1%	200%
Target	50th percentile	$8.85	4.9%	100%
Threshold	10th percentile	$8.34	4.5%	0%

TSR is measured relative to a peer group of companies that are believed to be most similar to Southern Company in both business model and investors. The peer group is subject to change based on merger and acquisition activity.

TSR Performance Share Peer Group for 2016 - 2018 Performance Period

Alliant Energy Corporation	Eversource Energy
Ameren Corporation	OGE Energy Corporation
American Electric Power Company, Inc.	PG&E Corporation
CMS Energy Corporation	Pinnacle West Capital Corporation
Consolidated Edison, Inc.	PPL Corporation
DTE Energy Company	SCANA Corporation
Duke Energy Corporation	Westar Energy Inc.
Edison International	WEC Energy Group, Inc.
Entergy Corporation	Xcel Energy Inc.

The following table shows the grant date fair value and target number of the long-term equity incentive awards granted in 2016.

	Target Value (% of base salary)	Relative TSR (50%)		Cumulative EPS (25%)		Equity-Weighted ROE (25%)		Total Long-Term Grant	
		Grant Date Fair Value ($)	Target Number of Shares (#)	Grant Date Fair Value ($)	Target Number of Shares (#)	Grant Date Fair Value ($)	Target Number of Shares (#)	Grant Date Fair Value ($)	Target Number of Shares (#)
S. W. Connally, Jr.	175	402,688	8,911	201,334	4,124	201,334	4,124	805,355	17,159
X. Liu	60	84,957	1,880	42,473	870	42,473	870	169,904	3,620
J. R. Fletcher	60	74,292	1,644	37,152	761	37,152	761	148,596	3,166
W. E. Smith	40	42,343	937	21,188	434	21,188	434	84,719	1,805
B. C. Terry	60	86,584	1,916	43,303	887	43,303	887	173,191	3,690

Other Details about the Program

Performance shares are not earned until the end of the three-year performance period and after certification of the results by the Compensation Committee. A participant can earn from 0 to 200% of the target number of performance shares granted at the beginning of the performance period based solely on achievement of the performance goals over the three-year performance period. Dividend equivalents are credited during the three-year performance period but are only paid out if and when the award is earned. If no performance shares are earned, then no dividends are paid out. Payout for performance between points will be interpolated on a straight-line basis.

Participants who retire during the performance period will receive the full amount of performance shares actually earned at the end of the three-year period. Participants who become disabled or die during the performance period will receive a prorated number of performance shares based on the performance shares actually earned at the end of the three-year period. A participant who terminates employment, other than due to retirement, death, or disability, forfeits all unearned performance shares.

The Compensation Committee retains the discretion to approve adjustments in determining actual performance goal achievement.

2014 Long-Term Incentive Compensation Grants

In 2014, 60% of the target value of the long-term incentive program was granted in the form of performance shares under the Performance Share Program. For the three-year performance period of 2014 - 2016, performance shares could be earned based on a relative TSR performance goal. The Southern Company three-year TSR performance relative to the custom peer group selected by the Compensation Committee was below the threshold performance level. As a result, no participants in the program, including the named executive officers, earned performance share awards for the 2014 - 2016 performance period.

TSR Performance Share Peer Group for 2014 - 2016 Performance Period

Alliant Energy Corporation	Eversource Energy
Ameren Corporation	PG&E Corporation
American Electric Power Company, Inc.	Pinnacle West Capital Corporation
CMS Energy Corporation	PPL Corporation
Consolidated Edison, Inc.	SCANA Corporation
DTE Energy Company	WEC Energy Group, Inc.
Duke Energy Corporation	Xcel Energy Inc.
Edison International	

	Target Performance Shares Granted (#)	Grant Date Target Value of Performance Shares ($)	Performance Shares Earned (#)	Value of Performance Shares Earned ($)
S. W. Connally, Jr.	8,274	310,606	0	0
X. Liu	2,320	87,093	0	0
J. R. Fletcher	1,350	50,679	0	0
W. E. Smith	748	28,080	0	0
B. C. Terry	2,608	97,904	0	0

In 2014, the remaining 40% of the target value of the long-term incentive program was granted in the form of stock options which vested one-third each year on the anniversary of the grant date. The 2014 stock option grants had an exercise price of $41.28 per share. The Common Stock closing stock price on December 30, 2016 was $49.19.

Timing of Performance-Based Compensation

The establishment of performance-based compensation goals and the granting of equity awards are not timed to coincide with the release of material, non-public information.

Southern Excellence Awards

Mr. Smith received a Southern Excellence Award in 2016 in the amount of $5,000 for the significant contributions and leadership he provided to Southern Company subsidiary PowerSecure during Hurricane Matthew restoration efforts.

Retirement and Severance Benefits

Certain post-employment compensation is provided to employees, including the named executive officers, consistent with Gulf Power's goal of providing market-based compensation and benefits.

Retirement Benefits

Substantially all employees of Gulf Power participate in the funded Pension Plan. Normal retirement benefits become payable when participants attain age 65. Employees are vested after completing five years of vesting service. One year of vesting service is equivalent to working at least 1,000 hours in a one-year period. Gulf Power also provides unfunded benefits to certain employees, including the named executive officers, under two nonqualified plans: the Supplemental Benefit Plan (Pension-Related) (SBP-P) and the Supplemental Executive Retirement Plan (SERP). The SBP-P and the SERP provide additional benefits the Pension Plan cannot pay due to limits prescribed for the Pension Plan under the Internal Revenue Code. See the Pension Benefits table and accompanying information for more pension-related benefits information.

Substantially all employees are eligible to participate in the Employee Savings Plan (ESP), Southern Company's 401(k) plan. The named executive officers are also eligible to participate in the Supplemental Benefit Plan (SBP), which is a nonqualified deferred compensation plan where employer contributions are made that are prohibited under the ESP due to limits prescribed for 401(k) plans under the Internal Revenue Code.

Gulf Power and its affiliates also provide supplemental retirement benefits to certain employees that were first employed by Gulf Power, or an affiliate of Gulf Power, in the middle of their careers. Gulf Power has had a supplemental retirement agreement (SRA) with Ms. Terry since 2010. Prior to her employment with the Southern Company system, Ms. Terry provided legal services to Southern Company's subsidiaries. Ms. Terry's agreement provides retirement benefits as if she was employed an additional 10 years. Ms. Terry must remain employed at Gulf Power or an affiliate of Gulf Power for 10 years from the effective date of the SRA before vesting in the benefits. This agreement provides a benefit which recognizes the expertise she brought to Gulf Power and provides a strong retention incentive to remain with Gulf Power, or one of its affiliates, for the vesting period and beyond.

Gulf Power also provides the Deferred Compensation Plan (DCP), which is an unfunded plan that permits participants to defer income as well as certain federal, state, and local taxes until a specified date or their retirement, disability, death, or other separation from service. Up to 50% of base salary and up to 100% of performance-based non-equity compensation may be deferred at the election of eligible employees. All of the named executive officers are eligible to participate in the DCP.

Change-in-Control Protections

Change-in-control protections, including severance pay and, in some situations, vesting or payment of long-term performance-based awards, are provided upon a change in control of Southern Company or Gulf Power coupled with an involuntary termination not for cause or a voluntary termination for "good reason." This means there is a "double trigger" before severance benefits are paid; *i.e.,* there must be both a change in control and a termination of employment. For 2016, severance payment amounts were two times salary plus target Performance Pay Program opportunity for Mr. Connally and one times salary plus Performance Pay Program opportunity for the other named executive officers. No excise tax gross-up would be provided. Change-in-control protections allow executive officers to focus on potential transactions that are in the best interest of shareholders.

Perquisites

Gulf Power provides limited perquisites to its executive officers, including the named executive officers, consistent with Gulf Power's goal of providing market-based compensation and benefits. The perquisites provided in 2016 are described in detail in the information accompanying the Summary Compensation Table. No tax assistance is provided on perquisites for the Chairman, President, and Chief Executive Officer, except on certain relocation-related benefits.

OTHER COMPENSATION POLICIES

Executive Stock Ownership Requirements

Officers of Gulf Power that are in a position of Vice President or above are subject to stock ownership requirements, which align the interests of officers and Southern Company stockholders by promoting a long-term focus and long-term share ownership. The ownership requirement is reduced by one-half at age 60.

The requirements are expressed as a multiple of base salary as shown below.

	Multiple of Salary without Counting Stock Options	Multiple of Salary Counting Portion of Vested Stock Options
S. W. Connally, Jr.	3 Times	6 Times
X. Liu	2 Times	4 Times
J. R. Fletcher	2 Times	4 Times
W. E. Smith	1 Times	2 Times
B. C. Terry	2 Times	4 Times

Ownership arrangements counted toward the requirements include shares owned outright, those held in Southern Company-sponsored plans, and Common Stock accounts in the DCP and the SBP. A portion of vested stock options may be counted, but in that case the ownership requirement is doubled.

Newly-elected and newly-promoted officers have approximately six years from the date of their election or promotion to meet the applicable ownership requirement. Compliance with the applicable ownership requirement is measured as of September 30 each year. All of the named executive officers are meeting their respective ownership requirements.

Clawback of Awards

Southern Company's Omnibus Incentive Compensation Plan provides that, if Southern Company or Gulf Power is required to prepare an accounting restatement due to material noncompliance as a result of misconduct, and if an executive officer of Gulf Power knowingly or grossly negligently engaged in or failed to prevent the misconduct or is subject to automatic forfeiture under the Sarbanes-Oxley Act of 2002, the executive officer must repay the amount of any payment in settlement of awards earned or accrued during the 12-month period following the first public issuance or filing that was restated.

Policy Regarding Hedging and Pledging of Common Stock

Southern Company's insider trading policy provides that employees, officers, and outside directors will not trade Southern Company options on the options market and will not engage in short sales. In early 2016, Southern Company added a "no pledging" provision to the insider trading policy that prohibits pledging of Common Stock for all Southern Company directors and executive officers, including the Gulf Power President and Chief Executive Officer.

COMPENSATION COMMITTEE REPORT

The Compensation Committee met with management to review and discuss the CD&A. Based on such review and discussion, the Compensation Committee recommended to the Southern Company Board of Directors that the CD&A be included in Gulf Power's Annual Report on Form 10-K for the fiscal year ended December 31, 2016.

Members of the Compensation Committee:

Henry A. Clark III, Chair
David J. Grain
Donald M. James
Dale E. Klein
Steven R. Specker

SUMMARY COMPENSATION TABLE

The Summary Compensation Table shows the amount and type of compensation received or earned in 2014, 2015, and 2016 by the named executive officers, except as noted below.

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Bonus ($) (d)	Stock Awards ($) (e)	Option Awards ($) (f)	Non-Equity Incentive Plan Compensation ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)	All Other Compensation ($) (i)	Total ($) (j)
S. W. Connally, Jr.	2016	453,521	—	805,355	—	510,624	536,810	24,523	2,330,833
President, Chief Executive Officer, and	2015	420,758	—	553,946	—	391,000	160,338	30,485	1,556,527
Director	2014	393,907	—	310,606	207,086	339,302	496,800	25,948	1,773,649
X. Liu	2016	281,309	—	169,904	—	220,461	187,312	20,897	879,883
Vice President and Chief Financial Officer	2015	265,380	—	154,865	—	188,996	59,936	283,417	952,594
J. R. Fletcher	2016	252,461	—	148,596	—	202,464	259,385	34,822	897,728
Vice President	2015	238,711	—	144,315	—	169,891	48,436	120,417	721,770
	2014	224,547	25,045	50,679	33,801	149,633	273,148	89,971	846,824
W. E. Smith	2016	218,707	5,000	84,719	—	158,447	257,056	14,843	738,772
Vice President	2015	203,401	—	81,813	—	128,461	42,181	144,040	599,896
B. C. Terry	2016	284,498	—	173,191	—	219,620	226,913	16,402	920,624
Vice President	2015	278,682	—	168,195	—	198,007	34,345	19,421	698,650
	2014	270,543	—	97,904	65,287	173,833	245,578	17,664	870,809

Column (a)

Ms. Liu and Mr. Smith first became named executive officers in 2015.

Column (d)

The amount shown for 2016 for Mr. Smith represents a Southern Excellence Award as described in the CD&A.

Column (e)

This column does not reflect the value of stock awards that were actually earned or received in 2016. Rather, as required by applicable rules of the SEC, this column reports the aggregate grant date fair value of performance shares granted in 2016. The value reported is based on the probable outcome of the performance conditions as of the grant date, using a Monte Carlo simulation model (50% of grant value) and the closing price of Common Stock on the grant date (50% of grant value). No amounts will be earned until the end of the three-year performance period on December 31, 2018. The value then can be earned based on performance ranging from 0 to 200%, as established by the Compensation Committee.

The aggregate grant date fair value of the performance shares granted in 2016 to the named executive officers, assuming that the highest level of performance is achieved, is as follows: Mr. Connally - $1,610,711; Ms. Liu - $339,808; Mr. Fletcher - $297,193; Mr. Smith - $169,438; Ms. Terry - $346,381 (200% of the amount shown in the table). See Note 8 to the financial statements of Gulf Power in Item 8 herein for a discussion of the assumptions used in calculating these amounts.

Column (f)

The Compensation Committee moved away from granting stock options as part of the long-term incentive program in 2015. No stock options were granted in 2015 or 2016. This column reports the aggregate grant date fair value of stock options granted in 2014.

Column (g)

The amounts in this column reflect actual payouts under the annual Performance Pay Program. The amount reported for 2016 is for the one-year performance period that ended on December 31, 2016. The Performance Pay Program is described in detail in the CD&A.

Column (h)

This column reports the aggregate change in the actuarial present value of each named executive officer's accumulated benefit under the Pension Plan and the supplemental pension plans (collectively, Pension Benefits) as of December 31 of the applicable year. The Pension Benefits as of each measurement date are based on the named executive officer's age, pay, and service accruals and the plan provisions applicable as of the measurement date. The actuarial present values as of each measurement date reflect the assumptions Gulf Power selected for cost purposes as of that measurement date; however, the named executive officers were assumed to remain employed at Gulf Power or another Southern Company subsidiary until their benefits commence at the pension plans' stated normal retirement date, generally age 65. As a result, the amounts in column (h) related to Pension Benefits represent the combined impact of several factors: growth in the named executive officer's Pension Benefits over the measurement year; impact on the total present values of one year shorter discounting period due to the named executive officer being one year closer to normal retirement; impact on the total present values attributable to changes in assumptions from measurement date to measurement date; and impact on the total present values attributable to plan changes between measurement dates.

This column also reports any above-market earnings on deferred compensation under the DCP. However, there were no above-market earnings on deferred compensation in the years reported.

Column (i)

The amounts reported for 2016 are itemized below.

	Relocation Benefits ($)	**Other Perquisites ($)**	**Tax Reimbursements ($)**	**Company Contributions to ESP ($)**	**Company Contributions to SBP ($)**	**Total ($)**
S. W. Connally, Jr.	—	1,385	—	12,407	10,731	24,523
X. Liu	500	6,097	42	13,425	832	20,897
J. R. Fletcher	12,059	2,754	7,133	12,875	—	34,822
W. E. Smith	—	2,107	2,038	8,458	2,241	14,843
B. C. Terry	—	1,721	172	13,515	994	16,402

Description of Perquisites

Relocation Benefits . Relocation benefits are provided to cover the costs associated with geographic relocation. In 2016, Ms. Liu received relocation-related benefits in the amount of $500 in connection with her 2015 relocation from Atlanta, Georgia to Pensacola, Florida. In 2016, Mr. Fletcher received relocation-related benefits in the amount of $12,059 in connection with his 2014 relocation from Atlanta to Pensacola. These amounts were for the shipment of household goods, incidental expenses related to the moves, and/or home sale and home repurchase assistance. Also, as provided in Gulf Power's relocation policy, tax assistance is provided on the taxable relocation benefits. If the named executive officer terminates within two years of relocation, these amounts must be repaid.

Other Perquisites includes financial planning, personal use of corporate aircraft, and other miscellaneous perquisites.

- Financial planning is provided for most officers of Gulf Power, including all of the named executive officers. Gulf Power provides an annual subsidy of up to $8,200 to be used for financial planning, tax preparation fees, and estate planning. In the initial year, the maximum allowed amount is $13,200.
- The Southern Company system has aircraft that are used to facilitate business travel. All flights on these aircraft must have a business purpose, except limited personal use that is associated with business travel is permitted for the President and Chief Executive Officer. Additionally, limited personal use related to relocation is permissible but must be approved. The amount reported for such personal use is the incremental cost of providing the benefit, primarily fuel costs. Also, if seating is available, Southern Company permits a spouse or other family member to accompany an employee on a flight. However, because in such cases the aircraft is being used for a business purpose, there is no incremental cost associated with the family travel, and no amounts are included for such travel. Any additional expenses incurred that are related to family travel are included.

- Other miscellaneous perquisites reflects the full cost to Gulf Power of providing the following items: personal use of company-provided computers, personal use of company-provided tickets for sporting and other entertainment events, and gifts distributed to and activities provided to attendees at company-sponsored events.

GRANTS OF PLAN-BASED AWARDS IN 2016

This table provides information on short-term and long-term incentive compensation awards made in 2016.

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			
Name (a)	**Grant Date (b)**	**Threshold ($) (c)**	**Target ($) (d)**	**Maximum ($) (e)**	**Threshold (#) (f)**	**Target (#) (g)**	**Maximum (#) (h)**	**Grant Date Fair Value of Stock and Option Awards ($) (i)**
S. W. Connally, Jr.		2,991	299,135	598,270				
	2/8/2016				172	17,159	34,318	805,355
X. Liu		1,274	127,434	254,868				
	2/8/2016				36	3,620	7,240	169,904
J. R. Fletcher		1,170	117,031	234,062				
	2/8/2016				32	3,166	6,332	148,596
W. E. Smith		916	91,588	183,176				
	2/8/2016				18	1,805	3,610	84,719
B. C. Terry		1,269	126,948	253,896				
	2/8/2016				37	3,690	7,380	173,191

Columns (c), (d), and (e)

These columns reflect the annual Performance Pay Program opportunity granted to the named executive officers in 2016. The information shown as "Threshold," "Target," and "Maximum" reflects the range of potential payouts established by the Compensation Committee. The actual amounts earned for 2016 are included in column (g) of the Summary Compensation Table.

Columns (f), (g), and (h)

These columns reflect the performance shares granted to the named executive officers in 2016. The information shown as "Threshold," "Target," and "Maximum" reflects the range of potential shares that can be earned established by the Compensation Committee. Earned performance shares and accrued dividends will be paid out in Common Stock following the end of the 2016-2018 performance period, based on the extent to which the performance goals are achieved. Any shares not earned are forfeited.

Column (i)

This column reflects the aggregate grant date fair value of the performance shares granted in 2016. 50% of the value is based on the probable outcome of the performance conditions as of the grant date using a Monte Carlo simulation model ($45.19), while the other 50% is based on the closing price of the Common Stock on the grant date ($48.82). The assumptions used in calculating these amounts are discussed in Note 8 to the financial statements of Gulf Power in Item 8 herein.

OUTSTANDING EQUITY AWARDS AT 2016 FISCAL YEAR-END

This table provides information about stock options and stock awards (performance shares) as of December 31, 2016.

	Option Awards				Stock Awards	
Name (a)	**Number of Securities Underlying Unexercised Options Exercisable (#) (b)**	**Number of Securities Underlying Unexercised Options Unexercisable (#) (c)**	**Option Exercise Price ($) (d)**	**Option Expiration Date (e)**	**Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (f)**	**Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (g)**
S. W. Connally, Jr.	16,100	0	37.97	02/14/2021		
	16,053	0	44.42	02/13/2022		
	66,905	0	44.06	02/11/2023		
	62,753	31,377	41.28	02/10/2024		
					12,922	635,633
					17,945	882,714
X. Liu	10,079	0	37.97	02/14/2021		
	9,976	0	44.42	02/13/2022		
	12,016	0	44.06	02/11/2023		
	17,595	8,798	41.28	02/10/2024		
					3,613	177,723
					3,786	186,233
J. R.Fletcher	0	5,121	41.28	02/10/2024		
					3,366	165,574
					3,311	162,868
W. E. Smith	5,037	0	44.42	2/13/2022		
	6,011	0	44.06	2/11/2023		
	5,676	2,838	41.28	2/10/2024		
					1,908	93,854
					1,888	92,871
B. C. Terry	18,163	0	44.42	02/13/2022		
	21,719	0	44.06	02/11/2023		
	0	9,892	41.28	02/10/2024		
					3,924	193,022
					3,859	189,824

Columns (b), (c), (d), and (e)

Stock options were not granted in 2015 or 2016. Stock options vest one-third per year on the anniversary of the grant date. Options granted from 2011 through 2013 with expiration dates from 2021 through 2023 were fully vested as of December 31, 2016. Options granted in 2014 became fully vested on February 10, 2017 and expire on February 10, 2024.

Options also fully vest upon death, total disability, or retirement and expire three years following death or total disability, five years following retirement, or, if earlier, on the original expiration date.

Columns (f) and (g)

In accordance with SEC rules, column (f) reflects the target number of performance shares granted under the Performance Share Program that can be earned at the end of each three-year performance period (January 1, 2015 through December 31, 2017 and January 1, 2016 through December 31, 2018). The number of shares reflected in column (f) also reflects the deemed reinvestments of dividends on the target number of performance shares. Dividends are credited over the performance period but are only received at the end of the performance period if the underlying performance shares are earned.

The performance shares granted for the January 1, 2014 through December 31, 2016 performance period vested on December 31, 2016. Due to Southern Company's TSR performance relative to the selected peer group, no performance shares were paid out to any participants, including the named executive officers.

The value in column (g) is derived by multiplying the number of shares in column (f) by the Common Stock closing price on December 30, 2016 ($49.19). The ultimate number of shares earned, if any, will be based on the actual performance results at the end of each respective performance period.

OPTION EXERCISES AND STOCK VESTED IN 2016

	Option Awards		Stock Awards	
Name (a)	Number of Shares Acquired on Exercise (#) (b)	Value Realized on Exercise ($) (c)	Number of Shares Acquired on Vesting (#) (d)	Value Realized on Vesting ($) (e)
S. W. Connally, Jr.	14,392	321,805	—	—
X. Liu	—	—	—	—
J. R. Fletcher	34,174	352,649	—	—
W. E. Smith	—	—	—	—
B. C. Terry	38,358	466,326	—	—

Columns (b) and (c)

Column (b) reflects the number of shares acquired upon the exercise of stock options during 2016 and column (c) reflects the value realized. The value realized is the difference in the market price over the exercise price on the exercise date.

Columns (d) and (e)

While the performance shares granted for the January 1, 2014 through December 31, 2016 performance period vested on December 31, 2016, there were no shares paid out due to the level of performance relative to the selected peer group. No other stock awards vested in 2016 for the named executive officers.

PENSION BENEFITS AT 2016 FISCAL YEAR-END

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit ($) (d)	Payments During Last Fiscal Year ($) (e)
	Pension Plan	25.17	658,389	0
	SBP-P	25.17	894,191	0
S.W. Connally, Jr.	SERP	25.17	545,110	0
	Pension Plan	16.92	455,857	0
	SBP-P	16.92	130,662	0
X. Liu	SERP	16.92	172,855	0
	Pension Plan	26.58	731,921	0
	SBP-P	26.58	184,848	0
J. R. Fletcher	SERP	26.58	254,833	0
	Pension Plan	29.17	726,236	0
	SBP-P	29.17	142,898	0
W. E. Smith	SERP	29.17	230,814	0
	Pension Plan	14.50	389,796	0
	SBP-P	14.50	128,349	0
	SERP	14.50	132,793	0
B. C. Terry	SRA	10.00	484,907	0

Pension Plan

The Pension Plan is a tax-qualified, funded plan. It is Southern Company's primary retirement plan. Substantially all employees participate in this plan after one year of service. Normal retirement benefits become payable when participants attain age 65 and complete five years of participation. The plan benefit equals the greater of amounts computed using a "1.7% offset formula" and a "1.25% formula," as described below. Benefits are limited to a statutory maximum.

The 1.7% offset formula amount equals 1.7% of final average pay times years of participation less an offset related to Social Security benefits. The offset equals a service ratio times 50% of the anticipated Social Security benefits in excess of $4,200. The service ratio adjusts the offset for the portion of a full career that a participant has worked. The highest three rates of payout of a participant's last

10 calendar years of service are averaged to derive final average pay. The rates of pay considered for this formula are the base salary rates with no adjustments for voluntary deferrals after 2008. A statutory limit restricts the amount considered each year; the limit for 2016 was $265,000.

The 1.25% formula amount equals 1.25% of final average pay times years of participation. For this formula, the final average pay computation is the same as above, but annual performance-based compensation earned each year is added to the base salary rates.

Early retirement benefits become payable once plan participants have, during employment, attained age 50 and completed 10 years of participation. Participants who retire early from active service receive benefits equal to the amounts computed using the same formulas employed at normal retirement. However, a 0.3% reduction applies for each month (3.6% for each year) prior to normal retirement that participants elect to have their benefit payments commence. For example, 64% of the formula benefits are payable starting at age 55. As of December 31, 2016, Mr. Fletcher and Mr. Smith were retirement-eligible.

The Pension Plan's benefit formulas produce amounts payable monthly over a participant's post-retirement lifetime. At retirement, plan participants can choose to receive their benefits in one of seven alternative forms of payment. All forms pay benefits monthly over the lifetime of the retiree or the joint lifetimes of the retiree and a beneficiary. A reduction applies if a retiring participant chooses a payment form other than a single life annuity. The reduction makes the value of the benefits paid in the form chosen comparable to what it would have been if benefits were paid as a single life annuity over the retiree's life.

Participants vest in the Pension Plan after completing five years of service. As of December 31, 2016, all of the named executive officers are vested in their Pension Plan benefits. Participants who terminate employment after vesting can elect to have their pension benefits commence at age 50 if they participated in the Pension Plan for 10 years. If such an election is made, the early retirement reductions that apply are actuarially determined factors and are larger than 0.3% per month.

Prior to January 1, 2017, if a participant died while actively employed and was either age 50 or vested in the Pension Plan as of date of death, benefits would have been payable to a beneficiary. For deaths occurring on or after January 1, 2017, a participant must be vested in the Pension Plan as of the date of death. After commencing, survivor benefits are payable monthly for the remainder of a survivor's life.

If participants become totally disabled, periods that Social Security or employer-provided disability income benefits are paid will count as service for benefit calculation purposes. The crediting of this additional service ceases at the point a disabled participant elects to commence retirement payments. Outside of this extra service crediting, the normal Pension Plan provisions apply to disabled participants.

The SBP-P

The SBP-P is an unfunded retirement plan that is not tax qualified. This plan provides high-paid employees any benefits that the Pension Plan cannot pay due to statutory pay/benefit limits. The SBP-P's vesting and early retirement provisions mirror those of the Pension Plan. Its disability provisions mirror those of the Pension Plan but cease upon a participant's separation from service.

The amounts paid by the SBP-P are based on the additional monthly benefit that the Pension Plan would pay if the statutory limits and pay deferrals were ignored. When a SBP-P participant separates from service, vested monthly benefits provided by the benefit formulas are converted into a single sum value. It equals the present value of what would have been paid monthly for an actuarially determined average post-retirement lifetime. The discount rate used in the calculation is based on the 30-year U.S. Treasury yields for the September preceding the calendar year of separation, but not more than six percent.

Vested participants terminating prior to becoming eligible to retire will be paid their single sum value as of September 1 following the calendar year of separation. If the terminating participant is retirement-eligible, the single sum value will be paid in 10 annual installments starting shortly after separation. The unpaid balance of a retiree's single sum will be credited with interest at the prime rate published in *The Wall Street Journal* . If the separating participant is a "key man" under Section 409A of the Internal Revenue Code, the first installment will be delayed for six months after the date of separation.

If a SBP-P participant dies after becoming vested in the Pension Plan, the beneficiary of the deceased participant will receive the installments the participant would have been paid upon retirement.

The SERP

The SERP is also an unfunded retirement plan that is not tax qualified. This plan provides high-paid employees additional benefits that the Pension Plan and the SBP-P would pay if the 1.7% offset formula calculations reflected a portion of annual performance-

based compensation. To derive the SERP benefits, a final average pay is determined reflecting participants' base rates of pay and their annual performance-based compensation amounts, whether or not deferred, to the extent they exceed 15% of those base rates (ignoring statutory limits). This final average pay is used in the 1.7% offset formula to derive a gross benefit. The Pension Plan and the SBP-P benefits are subtracted from the gross benefit to calculate the SERP benefit. The SERP's early retirement, survivor benefit, disability, and form of payment provisions mirror the SBP-P's provisions. However, except upon a change in control, SERP benefits do not vest until participants retire, so no benefits are paid if a participant terminates prior to becoming retirement-eligible. More information about vesting and payment of SERP benefits following a change in control is included under Potential Payments upon Termination or Change in Control. Effective January 1, 2016, participation in the SERP was closed to new participants.

SRA

Gulf Power also provides supplemental retirement benefits to certain employees that were first employed by Gulf Power, or an affiliate of Gulf Power, in the middle of their careers and generally provide for additional retirement benefits by giving credit for years of employment prior to employment with Gulf Power or one of its affiliates. These supplemental retirement benefits are also unfunded and not tax-qualified. Information about the SRA with Ms. Terry is included in the CD&A.

Pension Benefit Assumptions

The following assumptions were used in the present value calculations for all pension benefits:

- Discount rate - 4.46% Pension Plan and 3.89% supplemental plans as of December 31, 2016,
- Retirement date - Normal retirement age (65 for all named executive officers),
- Mortality after normal retirement - Adjusted RP-2014 mortality tables with generational projections,
- Mortality, withdrawal, disability, and retirement rates prior to normal retirement - None,
- Form of payment for Pension Benefits:
    - Male retirees: 25% single life annuity; 25% level income annuity; 25% joint and 50% survivor annuity; and 25% joint and 100% survivor annuity,
    - Female retirees: 50% single life annuity; 30% level income annuity; 15% joint and 50% survivor annuity; and 5% joint and 100% survivor annuity,
- Spouse ages - Wives two years younger than their husbands,
- Annual performance-based compensation earned but unpaid as of the measurement date - 130% of target opportunity percentages times base rate of pay for year amount is earned, and
- Installment determination - 3.75% discount rate for single sum calculation and 4.25% prime rate during installment payment period.

For all of the named executive officers, the number of years of credited service for the Pension Plan, the SBP-P, and the SERP is one year less than the number of years of employment.

NONQUALIFIED DEFERRED COMPENSATION AS OF 2016 FISCAL YEAR-END

Name (a)	Executive Contributions in Last FY ($) (b)	Employer Contributions in Last FY ($) (c)	Aggregate Earnings in Last FY ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE ($) (f)
S. W. Connally, Jr.	27,230	10,731	14,263	—	196,129
X. Liu	47,249	832	6,153	—	187,251
J. R. Fletcher	—	—	—	—	—
W. E. Smith	69,491	2,241	7,520	—	180,315
B. C. Terry	99,004	994	22,977	—	488,758

Southern Company provides the DCP, which is designed to permit participants to defer income as well as certain federal, state, and local taxes until a specified date or their retirement or other separation from service. Up to 50% of base salary and up to 100% of performance-based non-equity compensation may be deferred at the election of eligible employees. All of the named executive officers are eligible to participate in the DCP.

DCP participants have two options for the deemed investments of the amounts deferred - the Stock Equivalent Account and the Prime Equivalent Account. Under the terms of the DCP, participants are permitted to transfer between investments at any time.
The amounts deferred in the Stock Equivalent Account are treated as if invested at an equivalent rate of return to that of an actual investment in Common Stock, including the crediting of dividend equivalents as such are paid by Southern Company from time to time. It provides participants with an equivalent opportunity for the capital appreciation (or loss) and income of that of a Southern Company stockholder. During 2016, the rate of return in the Stock Equivalent Account was 9.99%.

Alternatively, participants may elect to have their deferred compensation deemed invested in the Prime Equivalent Account, which is treated as if invested at a prime interest rate compounded monthly, as published in *The Wall Street Journal* as the base rate on corporate loans posted as of the last business day of each month by at least 75% of the United States' largest banks. The interest rate earned on amounts deferred during 2016 in the Prime Equivalent Account was 3.59%.

Column (b)

This column reports the actual amounts of compensation deferred under the DCP by each named executive officer in 2016. The amount of salary deferred by the named executive officers, if any, is included in the Salary column in the Summary Compensation Table. The amounts of performance-based compensation deferred in 2016 were the amounts that were earned as of December 31, 2015 but not payable until the first quarter of 2016. These amounts are not reflected in the Summary Compensation Table because that table reports performance-based compensation that was earned in 2016 but not payable until early 2017. These deferred amounts may be distributed in a lump sum or in up to 10 annual installments at termination of employment or in a lump sum at a specified date, at the election of the participant.

Column (c)

This column reflects contributions under the SBP. Under the Internal Revenue Code, employer-matching contributions are prohibited under the ESP on employee contributions above stated limits in the ESP, and, if applicable, above legal limits set forth in the Internal Revenue Code. The SBP is a nonqualified deferred compensation plan under which contributions are made that are prohibited from being made in the ESP. The contributions are treated as if invested in Common Stock and are payable in cash upon termination of employment in a lump sum or in up to 20 annual installments, at the election of the participant. The amounts reported in this column also were reported in the All Other Compensation column in the Summary Compensation Table.

Column (d)

This column reports earnings or losses on compensation the named executive officers elected to defer and on employer contributions under the SBP.

Column (f)

This column includes amounts that were deferred under the DCP and contributions under the SBP in prior years and reported in Gulf Power's prior years' Annual Reports on Form 10-K. The following chart shows the amounts reported in Gulf Power's prior years' Annual Reports on Form 10-K.

Name	Amounts Deferred under the DCP Prior to 2016 and Reported in Prior Years' Annual Reports on Form 10-K ($)	Employer Contributions under the SBP Prior to 2016 and Reported in Prior Years' Annual Reports on Form 10-K ($)	Total ($)
S. W. Connally, Jr.	31,742	26,830	58,572
X. Liu	—	19	19
J. R. Fletcher	—	—	—
W. E. Smith	49,139	1,563	50,702
B. C. Terry	374,074	2,186	376,260

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

This section describes and estimates payments that could be made to the named executive officers serving as of December 31, 2016 under different termination and change-in-control events. The estimated payments would be made under the terms of Southern Company's compensation and benefit program or the change-in-control severance program. All of the named executive officers are participants in Southern Company's change-in-control severance program for officers. The amount of potential payments is calculated as if the triggering events occurred as of December 31, 2016 and assumes that the price of Common Stock is the closing market price on December 30, 2016.

Description of Termination and Change-in-Control Events

Different types of termination and change-in-control events that can affect the treatment of payments under the compensation and benefit programs are listed below. No payments are made under the change-in-control severance program unless, within two years of the change in control, the named executive officer is involuntarily terminated or voluntarily terminates for good reason.

Traditional Termination Events

- Retirement or Retirement-Eligible - Termination of a named executive officer who is at least 50 years old and has at least 10 years of credited service.
- Resignation - Voluntary termination of a named executive officer who is not retirement-eligible.
- Lay Off - Involuntary termination of a named executive officer who is not retirement-eligible not for cause.
- Involuntary Termination - Involuntary termination of a named executive officer for cause. Cause includes individual performance below minimum performance standards and misconduct, such as violation of the Company's Drug and Alcohol Policy.
- Death or Disability - Termination of a named executive officer due to death or disability.

Change-in-Control-Related Events

At the Southern Company or Gulf Power level:

- Southern Company Change-in-Control I - Consummation of an acquisition by another entity of 20% or more of Common Stock or, following consummation of a merger with another entity, Southern Company's stockholders own 65% or less of the entity surviving the merger.
- Southern Company Change-in-Control II - Consummation of an acquisition by another entity of 35% or more of Common Stock or, following consummation of a merger with another entity, Southern Company's stockholders own less than 50% of Southern Company surviving the merger.
- Southern Company Does Not Survive a Merger - Consummation of a merger or other event and Southern Company is not the surviving company or the Common Stock is no longer publicly traded.
- Company Change-in-Control - Consummation of an acquisition by another entity, other than another subsidiary of Southern Company, of 50% or more of the stock of Gulf Power, consummation of a merger with another entity and Gulf Power is not the surviving company, or the sale of substantially all the assets of Gulf Power.

At the employee level:

- Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason - Employment is terminated within two years of a change in control, other than for cause, or the employee voluntarily terminates for good reason. Good reason for voluntary termination within two years of a change in control generally is satisfied when there is a material reduction in salary, performance-based compensation opportunity, or benefits; relocation of over 50 miles; or a diminution in duties and responsibilities.

The following chart describes the treatment of different pay and benefit elements in connection with the Traditional Termination Events as described above.

Program	Retirement/ Retirement-Eligible	Lay Off (Involuntary Termination Not For Cause)	Resignation	Death or Disability	Involuntary Termination (For Cause)
Pension Benefits Plans	Benefits payable as described in the notes following the Pension Benefits table.	Benefits payable as described in the notes following the Pension Benefits table.	Benefits payable as described in the notes following the Pension Benefits table.	Benefits payable as described in the notes following the Pension Benefits table.	Benefits payable as described in the notes following the Pension Benefits table.
Annual Performance Pay Program	Prorated if before 12/31.	Prorated if before 12/31.	Forfeit.	Prorated if before 12/31.	Forfeit.
Stock Options	Vest; expire earlier of original expiration date or five years.	Vested options expire in 90 days; unvested are forfeited.	Vested options expire in 90 days; unvested are forfeited.	Vest; expire earlier of original expiration date or three years.	Forfeit.
Performance Shares	No proration if retirement prior to end of performance period. Will receive full amount actually earned.	Forfeit.	Forfeit.	Death - prorated based on number of months employed during performance period. Disability - not affected. Will receive full amount actually earned.	Forfeit.
Financial Planning Perquisite	Continues for one year.	Terminates.	Terminates.	Continues for one year.	Terminates.
DCP	Payable per prior elections (lump sum or up to 10 annual installments).	Payable per prior elections (lump sum or up to 10 annual installments).	Payable per prior elections (lump sum or up to 10 annual installments).	Payable to beneficiary or participant per prior elections. Amounts deferred prior to 2005 can be paid as a lump sum per the benefit administration committee's discretion.	Payable per prior elections (lump sum or up to 10 annual installments).
SBP - non-pension related	Payable per prior elections (lump sum or up to 20 annual installments).	Payable per prior elections (lump sum or up to 20 annual installments).	Payable per prior elections (lump sum or up to 20 annual installments).	Payable to beneficiary or participant per prior elections. Amounts deferred prior to 2005 can be paid as a lump sum per the benefit administration committee's discretion.	Payable per prior elections (lump sum or up to 20 annual installments).

The following chart describes the treatment of payments under compensation and benefit programs under different change-in-control events, except the Pension Plan. The Pension Plan is not affected by change-in-control events.

Program	Southern Company Change in Control I	Southern Company Change in Control II	Southern Company Does Not Survive Merger or Gulf Power Change in Control	Involuntary Change-in-Control-Related Termination or Voluntary Change-in-Control-Related Termination for Good Reason
Nonqualified Pension Benefits (except SRA)	All SERP-related benefits vest if participants vested in tax-qualified pension benefits; otherwise, no impact. SBP-P benefits vest for all participants and single sum value of benefits earned to change-in-control date paid following termination or retirement.	Benefits vest for all participants and single sum value of benefits earned to the change-in-control date paid following termination or retirement.	Benefits vest for all participants and single sum value of benefits earned to the change-in-control date paid following termination or retirement.	Based on type of change-in-control event.
SRA	Not affected.	Not affected.	Not affected.	Vest.
Annual Performance Pay Program	If no program termination, paid at greater of target or actual performance. If program terminated within two years of change in control, prorated at target performance level.	If no program termination, paid at greater of target or actual performance. If program terminated within two years of change in control, prorated at target performance level.	Prorated at target performance level.	If not otherwise eligible for payment, if the program is still in effect, prorated at target performance level.
Stock Options	Not affected.	Not affected.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
Performance Shares	Not affected.	Not affected.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
DCP	Not affected.	Not affected.	Not affected.	Not affected.
SBP	Not affected.	Not affected.	Not affected.	Not affected.
Severance Benefits	Not applicable.	Not applicable.	Not applicable.	One or two times base salary plus target annual performance-based pay.
Healthcare Benefits	Not applicable.	Not applicable.	Not applicable.	Up to five years participation in group healthcare plan plus payment of two or three years' premium amounts.
Outplacement Services	Not applicable.	Not applicable.	Not applicable.	Six months.

Potential Payments

This section describes and estimates payments that would become payable to the named executive officers upon a termination or change in control as of December 31, 2016 .

Pension Benefits

The amounts that would have become payable to the named executive officers if the Traditional Termination Events occurred as of December 31, 2016 under the Pension Plan, the SBP-P, the SERP, and, if applicable, an SRA are itemized in the following chart. The amounts shown under the Retirement column are amounts that would have become payable to the named executive officers that were retirement-eligible on December 31, 2016 and are the monthly Pension Plan benefits and the first of 10 annual installments from the SBP-P and the SERP. The amounts shown under the Resignation or Involuntary Termination column are the amounts that would have become payable to the named executive officers who were not retirement-eligible on December 31, 2016 and are the monthly Pension Plan benefits that would become payable as of the earliest possible date under the Pension Plan and the single sum value of benefits earned up to the termination date under the SBP-P, paid as a single payment rather than in 10 annual installments. Benefits under the SERP would be forfeited. The amounts shown that are payable to a spouse in the event of the death of the named executive officer are the monthly amounts payable to a spouse under the Pension Plan and the first of 10 annual installments from the SBP-P and the SERP.

The amounts in this chart are very different from the pension values shown in the Summary Compensation Table and the Pension Benefits table. Those tables show the present values of all the benefit amounts anticipated to be paid over the lifetimes of the named executive officers and their spouses. Those plans are described in the notes following the Pension Benefits table. Only Mr. Fletcher and Mr. Smith were retirement-eligible on December 31, 2016. The SRA for Ms. Terry contains an additional service requirement for benefit eligibility which was not met as of December 31, 2016. Therefore, she was not eligible to receive retirement benefits under the agreement. However, death benefits would be paid to her surviving spouse.

Name		Retirement ($)	Resignation or Involuntary Termination ($)	Death (payments to a spouse) ($)
S. W. Connally, Jr.	Pension	n/a	2,830	4,240
	SBP-P	n/a	1,135,437	122,294
	SERP	n/a	—	74,552
X. Liu	Pension	n/a	1,884	2,849
	SBP-P	n/a	166,291	18,041
	SERP	n/a	—	23,867
J. R. Fletcher	Pension	4,144	All plans treated as retiring	3,882
	SBP-P	23,062		23,062
	SERP	31,794		31,794
W. E. Smith	Pension	4,247	All plans treated as retiring	3,641
	SBP-P	18,189		18,189
	SERP	29,380		29,380
B. C. Terry	Pension	n/a	1,628	2,463
	SBP-P	n/a	163,196	17,892
	SERP	n/a	—	18,511
	SRA	n/a	—	67,596

As described in the Change-in-Control chart, the only change in the form of payment, acceleration, or enhancement of the pension benefits is that the single sum value of benefits earned up to the change-in-control date under the SBP-P, the SERP, and the SRA could be paid as a single payment rather than in 10 annual installments. Also, the SERP benefits vest for participants who are not retirement-eligible upon a change in control. Estimates of the single sum payment that would have been made to the named executive officers, assuming termination as of December 31, 2016 following a change-in-control-related event, other than a Southern Company Change-in-Control I (which does not impact how pension benefits are paid), are itemized below. These amounts would be paid instead of the benefits shown in the Traditional Termination Events chart above; they are not paid in addition to those amounts.

Name	SBP-P ($)	SERP ($)	SRA ($)	Total ($)
S. W. Connally, Jr.	1,116,343	680,537	—	1,796,880
X. Liu	163,495	216,289	—	379,784
J. R. Fletcher	230,621	317,936	—	548,557
W. E. Smith	181,892	293,798	—	475,690
B. C. Terry	160,452	166,007	606,192	932,651

The pension benefit amounts in the tables above were calculated as of December 31, 2016 assuming payments would begin as soon as possible under the terms of the plans. Accordingly, appropriate early retirement reductions were applied. Any unpaid annual performance-based compensation was assumed to be paid at 1.30 times the target level. Pension Plan benefits were calculated assuming each named executive officer chose a single life annuity form of payment, because that results in the greatest monthly benefit. The single sum values were based on a 2.95 % discount rate .

Annual Performance Pay Program
The amount payable if a change in control had occurred on December 31, 2016 is the greater of target or actual performance. Because actual payouts for 2016 performance were above the target level for all of the named executive officers, the amount that would have been payable to the named executive officers was the actual amount paid as reported in the Summary Compensation Table .

Stock Options and Performance Shares (Equity Awards)
Equity Awards would be treated as described in the Termination and Change-in-Control charts above. If Southern Company consummates a merger and is not the surviving company, all Equity Awards vest. However, there is no payment associated with Equity Awards in that situation unless the participants' Equity Awards cannot be converted into surviving company awards. In that event, the value of outstanding Equity Awards would be paid to the named executive officers. In addition, if there is an Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason, Equity Awards vest.

For stock options, the value is the excess of the exercise price and the closing price of Common Stock on December 30, 2016. The value of performance shares is calculated using the closing price of Common Stock on December 30, 2016.

The chart below shows the number of stock options for which vesting would be accelerated and the amount that would be payable if there were no conversion to the surviving company's stock options. It also shows the number and value of performance shares that would be paid.

Name	Number of Equity Awards with Accelerated Vesting (#)		Total Number of Equity Awards Following Accelerated Vesting (#)		Total Payable in Cash without Conversion of Equity Awards ($)
	Stock Options	Performance Shares	Stock Options	Performance Shares	
S. W. Connally, Jr.	31,377	30,867	193,188	30,867	2,863,353
X. Liu	8,798	7,399	58,464	7,399	795,039
J. R. Fletcher	5,121	6,677	5,121	6,677	368,949
W. E. Smith	2,838	3,796	19,562	3,796	308,934
B. C. Terry	9,892	7,783	49,774	7,783	659,147

DCP and SBP
The aggregate balances reported in the Nonqualified Deferred Compensation table would be payable to the named executive officers as described in the Traditional Termination and Change-in-Control-Related Events charts above. There is no enhancement or acceleration of payments under these plans associated with termination or change-in-control events, other than the lump-sum payment opportunity described in the above charts. The lump sums that would be payable are those that are reported in the Nonqualified Deferred Compensation table .

Healthcare Benefits
Mr. Smith and Mr. Fletcher are the only named executive officers who were retirement-eligible as of December 31, 2016. Healthcare benefits are provided to retirees, and there is no incremental payment associated with the termination or change-in-control events, except in the case of a change-in-control-related termination, as described in the Change-in-Control-Related Events chart. Because the other named executive officers were not retirement-eligible, healthcare benefits would not become available until each reaches age 50, except in the case of a change-in-control-related termination, as described in the Change-in-Control-Related Events chart.

The estimated cost of providing Ms. Liu and Ms. Terry two years of healthcare insurance premiums is approximately $19,391 and $11,772, respectively. The estimated cost of providing Mr. Connally three years of healthcare insurance premiums is approximately $47,656 .

Financial Planning Perquisite
An additional year of the financial planning perquisite, which is set at a maximum of $8,200 per year, will be provided after retirement for retirement-eligible named executive officers.

There are no other perquisites provided to the named executive officers under any of the traditional termination or change-in-control-related events .

Severance Benefits
The named executive officers are participants in a change-in-control severance plan. The plan provides severance benefits, including outplacement services, if within two years of a change in control, they are involuntarily terminated, not for cause, or they voluntarily terminate for good reason. The severance benefits are not paid unless the named executive officer releases the employing company from any claims he or she may have against the employing company.

- As of December 31, 2016, the severance payment was two times the base salary and target payout under the annual Performance Pay Program for Mr. Connally and one times the base salary and target payout under the annual Performance Pay Program for the other named executive officers.
- The estimated cost of providing the six months of outplacement services is $6,000 per named executive officer.
- If any portion of the severance amount constitutes an "excess parachute payment" under Section 280G of the Internal Revenue Code and is therefore subject to an excise tax, the severance amount will be reduced unless the after-tax "unreduced amount" exceeds the after-tax "reduced amount." Excise tax gross-ups will not be provided on change-in-control severance payments.

The table below estimates the severance payments that would be made to the named executive officers if they were terminated as of December 31, 2016 in connection with a change in control.

Name	**Severance Amount ($)**
S. W. Connally, Jr.	1,518,687
X. Liu	410,622
J. R. Fletcher	377,098
W. E. Smith	320,558
B. C. Terry	409,056

DIRECTOR COMPENSATION

Only non-employee directors of Gulf Power are compensated for service on the board of directors.

During 2016, the pay components for non-employee directors were:

Annual cash retainer:	$22,000 per year
Annual stock retainer:	$19,500 per year in Common Stock
Board meeting fees:	If more than five meetings are held in a calendar year, $1,200 will be paid for participation beginning with the sixth meeting.
Committee meeting fees:	If more than five meetings of any one committee are held in a calendar year, $1,000 will be paid for participation in each meeting of that committee beginning with the sixth meeting.

DIRECTOR DEFERRED COMPENSATION PLAN

Any deferred quarterly equity grants or stock retainers are required to be deferred in the Deferred Compensation Plan For Outside Directors of Gulf Power Company (Director Deferred Compensation Plan) and are invested in Common Stock units which earn dividends as if invested in Common Stock. Earnings are reinvested in additional stock units. Upon leaving the board, distributions are made in shares of Common Stock or cash.

In addition, directors may elect to defer up to 100% of their remaining compensation in the Director Deferred Compensation Plan until membership on the board ends. Deferred compensation may be invested as follows, at the director's election:

- in Common Stock units which earn dividends as if invested in Common Stock and are distributed in shares of Common Stock or cash upon leaving the board; or
- at the prime interest rate which is paid in cash upon leaving the board.

All investments and earnings in the Director Deferred Compensation Plan are fully vested and, at the election of the director, may be distributed in a lump sum payment or in up to 10 annual distributions after leaving the board. A grantor trust has been established that primarily holds Common Stock that funds the Common Stock units that are distributed in shares of Common Stock. Directors have voting rights in the shares held in the trust attributable to these units.

DIRECTOR COMPENSATION TABLE

The following table reports all compensation to Gulf Power's non-employee directors during 2016, including amounts deferred in the Director Deferred Compensation Plan. Non-employee directors do not receive non-equity incentive plan compensation or stock option awards, and there is no pension plan for non-employee directors **.**

Name	Fees Earned or Paid in Cash ($) (1)	Stock Awards ($) (2)	All Other Compensation ($) (3)	Total ($)
Allan G. Bense	22,000	19,500	100	41,600
Deborah H. Calder	22,000	19,500	100	41,600
William C. Cramer, Jr.	22,000	19,500	100	41,600
Julian B. MacQueen	22,000	19,500	100	41,600
J. Mort O'Sullivan III	22,000	19,500	100	41,600
Michael T. Rehwinkel	22,000	19,500	100	41,600
Winston E. Scott	22,000	19,500	100	41,600

(1) Includes amounts voluntarily deferred in the Director Deferred Compensation Plan.

(2) Includes fair market value of equity grants on grant dates. All such stock awards are vested immediately upon grant.

(3) Includes value of charitable contribution made in each director's name.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The Compensation Committee is made up of independent directors of Southern Company who have never served as executive officers of Southern Company or Gulf Power. During 2016, none of Southern Company's or Gulf Power's directors or executive officers served on the board of directors of any entities whose executive officers serve on the Compensation Committee.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Security Ownership (Applicable to Gulf Power only).

Security Ownership of Certain Beneficial Owners . Southern Company is the beneficial owner of 100% of the outstanding common stock of Gulf Power. The number of outstanding shares reported in the table below is as of January 31, 2017.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common Stock	The Southern Company 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308		100%
	Registrant: Gulf Power	7,392,717	

Security Ownership of Management. The following table shows the number of shares of Common Stock of Southern Company owned by the directors, nominees, and executive officers of Gulf Power as of December 31, 2016. It is based on information furnished by the directors, nominees, and executive officers. The shares beneficially owned by all directors, nominees, and executive officers as a group constitute less than one percent of the total number of shares of Common Stock of Southern Company outstanding on December 31, 2016.

		Shares Beneficially Owned Include:		
Name of Directors, Nominees, and Executive Officers	**Shares Beneficially Owned (1)**	**Deferred Stock Units (2)**	**Shares Individuals Have Rights to Acquire Within 60 Days (3)**	**Shares Held By Family Member (4)**
S. W. Connally, Jr.	209,213	0	193,188	0
Allan G. Bense	11,240	0	0	0
Deborah H. Calder	3,482	2,929	0	0
William C. Cramer, Jr.	20,567	20,567	0	0
Julian B. MacQueen	1,919	0	0	0
J. Mort O'Sullivan III	5,226	5,226	0	0
Michael T. Rehwinkel	1,489	0	0	0
Winston E. Scott	8,622	0	0	0
Jim R. Fletcher	12,225	0	5,121	0
Xia Liu	63,406	0	58,464	0
Wendell E. Smith	24,230	0	19,562	0
Bentina C. Terry	60,554	0	49,774	633
Directors, Nominees, and Executive Officers as a group (13 people)	467,903	28,722	355,408	633

(1) "Beneficial ownership" means the sole or shared power to vote, or to direct the voting of, a security and/or investment power with respect to a security or any combination thereof.

(2) Indicates the number of deferred stock units held under the Director Deferred Compensation Plan.

(3) Indicates shares of Common Stock that certain executive officers have the right to acquire within 60 days. Shares indicated are included in the Shares Beneficially Owned column.

(4) Shares indicated are included in the Shares Beneficially Owned column.

Changes in Control. Southern Company and Gulf Power know of no arrangements which may at a subsequent date result in any change in control.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

Transactions with Related Persons.

In 2016, Mr. Antonio Terry, the spouse of Ms. Bentina Terry, an executive officer of Gulf Power, was employed by Gulf Power as a Senior Engineer and received compensation of $134,076.

Review, Approval or Ratification of Transactions with Related Persons.

Gulf Power does not have a written policy pertaining solely to the approval or ratification of "related party transactions" and has a robust system for identifying potential related party transactions.

- The Southern Company Audit Committee is responsible for overseeing the Code of Ethics, which includes policies relating to conflicts of interest. The Code of Ethics requires that all employees and directors avoid conflicts of interest, defined as situations where the person's private interests conflict, or even appear to conflict, with the interests of Southern Company as a whole.
- Southern Company also has a Contract Manual and other formal written procurement policies and procedures that guide the purchase of goods and services, including requiring competitive bids for purchases of materials for $10,000 and above and for purchases of services for $25,000 and above or approval based on documented business needs for sole sourcing arrangements.
- At least annually, each director and executive officer completes a detailed questionnaire that asks about any business relationship that may give rise to a conflict of interest and all transactions in which the Southern Company or a subsidiary is involved and in which the executive officer, director, or a related party has a direct or indirect material interest.
- Southern Company also conducts a review of financial systems to identify potential conflicts of interest and related party transactions.

The approval and ratification of any related party transactions would be subject to these written policies and procedures which include:

- A determination of the need for the goods and services;
- Preparation and evaluation of requests for proposals by the lead support organization;
- The writing of contracts;
- Controls and guidance regarding the evaluation of the proposals; and
- Negotiation of contract terms and conditions.

As appropriate, these contracts are also reviewed by individuals in the legal, accounting, and/or risk management/services departments prior to being approved by the responsible individual. The responsible individual will vary depending on the department requiring the goods and services, the dollar amount of the contract, and the appropriate individual within that department who has the authority to approve a contract of the applicable dollar amount.

In the ordinary course of the Southern Company system's business, electricity is provided to some directors and entities with which the directors are associated on the same terms and conditions as provided to other customers of the Southern Company system.

Director Independence.

The board of directors of Gulf Power consists of seven non-employee directors (Ms. Deborah H. Calder and Messrs. Allan G. Bense, William C. Cramer, Jr., Julian B. MacQueen, J. Mort O'Sullivan, III, Michael T. Rehwinkel, and Winston E. Scott) and Mr. Connally.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following represents the fees billed to Gulf Power and Southern Power for the last two fiscal years by Deloitte & Touche LLP, each company's principal public accountant for 2016 and 2015:

	2016	2015
	(in thousands)	
Gulf Power		
Audit Fees (1)	$ 1,346	$ 1,359
Audit-Related Fees	3	2
Tax Fees	—	—
All Other Fees (2)	2	1
Total	$ 1,351	$ 1,362
Southern Power		
Audit Fees (1)	$ 1,817	$ 1,478
Audit-Related Fees	372	3
Tax Fees	—	—
All Other Fees (2)	6	5
Total	$ 2,195	$ 1,486

(1) Includes services performed in connection with financing transactions.
(2) Represents registration fees for attendance at Deloitte & Touche LLP-sponsored education seminars in 2015 and 2016 and subscription fees for Deloitte & Touche LLP's technical accounting research tool in 2015.

The following represents the fees billed to Southern Company Gas for the last two fiscal years by PricewaterhouseCoopers LLP, Southern Company Gas' principal public accountant for 2015 and through February 11, 2016, and Deloitte & Touche LLP, Southern Company Gas' principal public accountant since February 11, 2016:

	2016	2015
	(in thousands)	
Audit Fees (1)	$ 5,131	$ 3,967
Audit-Related Fees (2)	59	88
Tax Fees (3)	65	75
All Other Fees (4)	7	—
Total	$ 5,262	$ 4,130

(1) Includes fees for services performed in connection with financing transactions billed by Deloitte & Touche LLP in 2016 and PricewaterhouseCoopers LLP in 2015. Also includes fees for audits of several subsidiaries by Deloitte & Touche LLP in 2016 and PricewaterhouseCoopers LLP in 2015.
(2) Represents fees for a review report on internal controls provided to third parties billed by Deloitte & Touche LLP in 2016 and PricewaterhouseCoopers LLP in 2015.
(3) Represents fees billed by Deloitte & Touche LLP for tax compliance services in 2016 and PricewaterhouseCoopers LLP for tax compliance, planning, and advisory services in 2015.
(4) Represents registration fees for attendance at Deloitte & Touche LLP-sponsored education seminars in 2016 and subscription fees for Deloitte & Touche LLP's technical accounting research tool in 2016.

The Southern Company Audit Committee (on behalf of Southern Company and its subsidiaries) adopted a Policy of Engagement of the Independent Auditor for Audit and Non-Audit Services that includes requirements for such Audit Committee to pre-approve audit and non-audit services provided by Deloitte & Touche LLP. All of the audit services provided

by Deloitte & Touche LLP in fiscal years 2016 and 2015 (described in the footnotes to the table above) and related fees were approved in advance by the Southern Company Audit Committee.

Prior to the closing of the Merger, the Southern Company Gas Audit Committee had responsibility for appointing, setting compensation, and overseeing the work of Southern Company Gas' independent registered public accounting firm. In recognition of this responsibility, Southern Company Gas' Audit Committee adopted a policy that required specific Audit Committee approval before any services were provided by the independent registered public accounting firm. All of the audit services provided by PricewaterhouseCoopers LLP in fiscal year 2015 and PricewaterhouseCoopers LLP and Deloitte & Touche LLP in fiscal year 2016 (described in the footnotes to the table above) prior to the closing of the Merger and related fees were approved in advance by the Southern Company Gas Audit Committee.

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report on Form 10-K:

(1) Financial Statements and Financial Statement Schedules:

Management's Report on Internal Control Over Financial Reporting for Southern Company and Subsidiary Companies is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Alabama Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Georgia Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Gulf Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Mississippi Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Southern Power and Subsidiary Companies is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Southern Company Gas and Subsidiary Companies is listed under Item 8 herein.

Reports of Independent Registered Public Accounting Firm on the financial statements and financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Company Gas and Subsidiary Companies, as well as the Report of Independent Registered Public Accounting Firm on the financial statements of Southern Power and Subsidiary Companies are listed under Item 8 herein.

The financial statements filed as a part of this report for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power and Subsidiary Companies, and Southern Company Gas and Subsidiary Companies are listed under Item 8 herein.

The financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Company Gas and Subsidiary Companies are listed in the Index to the Financial Statement Schedules at page S-1.

The financial statements of Southern Natural Gas Company, L.L.C. as of December 31, 2016 and for the four months ended December 31, 2016 are provided by Southern Company Gas as separate financial statements of subsidiaries not consolidated pursuant to Rule 3-09 of Regulation S-X, and are incorporated by reference herein from Exhibit 99(g) hereto.

(2) Exhibits:

Exhibits for Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and Southern Company Gas are listed in the Exhibit Index at page E-1.

Item 16. FORM 10-K SUMMARY

None.

THE SOUTHERN COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

THE SOUTHERN COMPANY

By: Thomas A. Fanning
Chairman, President, and
Chief Executive Officer

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 21, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Thomas A. Fanning
Chairman, President, and
Chief Executive Officer
(Principal Executive Officer)

Art P. Beattie
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Ann P. Daiss
Comptroller and Chief Accounting Officer
(Principal Accounting Officer)

Directors:

Juanita Powell Baranco
Jon A. Boscia
Henry A. Clark III
David J. Grain
Veronica M. Hagen
Warren A. Hood, Jr.
Linda P. Hudson
Donald M. James
John D. Johns
Dale E. Klein
William G. Smith, Jr.
Steven R. Specker
Larry D. Thompson
E. Jenner Wood III

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 21, 2017

ALABAMA POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

ALABAMA POWER COMPANY

By: *Mark A. Crosswhite*
Chairman, President, and Chief Executive Officer

By: */s/Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: *February 21, 2017*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Mark A. Crosswhite
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Anita Allcorn-Walker
Vice President and Comptroller
(Principal Accounting Officer)

Directors:

Whit Armstrong
David J. Cooper, Sr.
O. B. Grayson Hall, Jr.
Anthony A. Joseph
Patricia M. King
James K. Lowder
Robert D. Powers
Catherine J. Randall
C. Dowd Ritter
R. Mitchell Shackleford, III

By: */s/Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: February 21, 2017

GEORGIA POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GEORGIA POWER COMPANY

By: *W. Paul Bowers*
Chairman, President, and Chief Executive Officer

By: */s/Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: *February 21, 2017*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

W. Paul Bowers
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

W. Ron Hinson
Executive Vice President, Chief Financial Officer,
and Treasurer
(Principal Financial Officer)

David P. Poroch
Comptroller and Vice President
(Principal Accounting Officer)

Directors:

Robert L. Brown, Jr.
Anna R. Cablik
Stephen S. Green
Kessel D. Stelling, Jr.
Jimmy C. Tallent
Charles K. Tarbutton
Beverly Daniel Tatum
Clyde C. Tuggle
Richard W. Ussery

By: */s/Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: *February 21, 2017*

GULF POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GULF POWER COMPANY

By: *S. W. Connally, Jr.*
Chairman, President, and Chief Executive Officer

By: */s/Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: *February 21, 2017*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

S. W. Connally, Jr.
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

Xia Liu
Vice President and Chief Financial Officer
(Principal Financial Officer)

Janet J. Hodnett
Comptroller
(Principal Accounting Officer)

Directors:

Allan G. Bense
Deborah H. Calder
William C. Cramer, Jr.
Julian B. MacQueen
J. Mort O'Sullivan, III
Michael T. Rehwinkel
Winston E. Scott

By: */s/Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: February 21, 2017

MISSISSIPPI POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

MISSISSIPPI POWER COMPANY

By: *Anthony L. Wilson*
Chairman, President, and Chief Executive Officer

By: */s/Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: *February 21, 2017*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Anthony L. Wilson
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

Moses H. Feagin
Vice President, Treasurer, and
Chief Financial Officer
(Principal Financial Officer)

Cynthia F. Shaw
Comptroller
(Principal Accounting Officer)

Directors:

Carl J. Chaney
L. Royce Cumbest
Thomas A. Dews
Mark E. Keenum
Christine L. Pickering
Phillip J. Terrell
M. L. Waters

By: */s/Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: February 21, 2017

SOUTHERN POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SOUTHERN POWER COMPANY

By: Joseph A. Miller
Chairman, President and Chief Executive Officer

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 21, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Joseph A. Miller
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

William C. Grantham
Senior Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Elliott L. Spencer
Comptroller and Corporate Secretary
(Principal Accounting Officer)

Directors:

Art P. Beattie
Thomas A. Fanning
Kimberly S. Greene
James Y. Kerr II
Mark S. Lantrip
Christopher C. Womack

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 21, 2017

SOUTHERN COMPANY GAS

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SOUTHERN COMPANY GAS

By: Andrew W. Evans
Chairman, President, and Chief Executive Officer

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 21, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Andrew W. Evans
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

Elizabeth W. Reese
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Grace A. Kolvereid
Senior Vice President, Accounting
(Principal Accounting Officer)

Directors:

Sandra N. Bane
Thomas D. Bell, Jr.
Charles R. Crisp
Brenda J. Gaines
Kimberly S. Greene
John E. Rau
James A. Rubright

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 21, 2017

Supplemental Information to be Furnished With Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act:

Southern Company Gas is not required to send an annual report or proxy statement to its sole shareholder and parent company, The Southern Company, and will not prepare such a report after filing this Annual Report on Form 10-K for fiscal year 2016. Accordingly, Southern Company Gas will not file an annual report with the Securities and Exchange Commission.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Southern Company

We have audited the consolidated financial statements of Southern Company and Subsidiaries (the Company) as of December 31, 2016 and 2015 , and for each of the three years in the period ended December 31, 2016 , and the Company's internal control over financial reporting as of December 31, 2016 , and have issued our report (which expresses an unqualified opinion and includes an explanatory paragraph regarding uncertainty relating to the rate recovery process with the Mississippi Public Service Commission regarding recovery of the cost of the Kemper Integrated Coal Gasification Combined Cycle) thereon dated February 21, 2017 ; such report is included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of the Company (page S-2) listed in Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 21, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Alabama Power Company

We have audited the financial statements of Alabama Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2016 and 2015 , and for each of the three years in the period ended December 31, 2016 , and have issued our report thereon dated February 21, 2017 ; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-3) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Birmingham, Alabama
February 21, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Georgia Power Company

We have audited the financial statements of Georgia Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2016 and 2015 , and for each of the three years in the period ended December 31, 2016 , and have issued our report thereon dated February 21, 2017 ; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-4) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 21, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Gulf Power Company

We have audited the financial statements of Gulf Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2016 and 2015 , and for each of the three years in the period ended December 31, 2016 , and have issued our report thereon dated February 21, 2017 ; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-5) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 21, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Mississippi Power Company

We have audited the financial statements of Mississippi Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2016 and 2015 , and for each of the three years in the period ended December 31, 2016 , and have issued our report (which expresses an unqualified opinion and includes an explanatory paragraph regarding uncertainty relating to the rate recovery process with the Mississippi Public Service Commission regarding recovery of the cost of the Kemper Integrated Coal Gasification Combined Cycle) thereon dated February 21, 2017 ; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-6) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 21, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Southern Company Gas

We have audited the consolidated financial statements of Southern Company Gas and Subsidiary Companies (formerly known as AGL Resources Inc.) (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2016 (Successor), and for the six-month periods ended June 30, 2016 (Predecessor) and December 31, 2016 (Successor), and have issued our report thereon dated February 21, 2017 ; such report is included elsewhere in this Form 10-K. As indicated in that report, we did not audit the financial statements of Southern Natural Gas Company, L.L.C. (SNG), the Company's investment in which is accounted for by the use of the equity method. The Company's consolidated financial statements include its equity investment in SNG of $1,394 million as of December 31, 2016 , and its earnings from its equity method investment in SNG of $56 million for the six-month period ended December 31, 2016 . Those statements were audited by other auditors, who have furnished their report to us (which expresses an unqualified opinion on SNG's financial statements and contains an emphasis of matter paragraph concerning the extent of its operations and relationships with affiliated entities), and our opinion, insofar as it relates to amounts included for SNG, is based solely on the report of the other auditors. Our audit also included the financial statement schedule of the Company for the six-month periods ended June 30, 2016 (Predecessor) and December 31, 2016 (Successor) (Page S-7) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 21, 2017

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Schedules I through V not listed above are omitted as not applicable or not required. A Schedule II for Southern Power Company and Subsidiary Companies is not being provided because there were no reportable items for the three-year period ended December 31, 2016 . Columns omitted from schedules filed have been omitted because the information is not applicable or not required.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2016 , 2015 , AND 2014
(Stated in Thousands of Dollars)

		Additions				
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Acquisitions	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts						
2016	$ 13,341	$ 39,959	$ (1,257)	$ 40,629	$ 49,243	$ 43,429
2015	18,253	31,074	—	—	35,986	13,341
2014	17,855	43,537	—	—	43,139	18,253

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

ALABAMA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2016 , 2015 , AND 2014
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2016	$ 9,597	$ 11,310	$ —	$ 10,420	$ 10,487
2015	9,143	13,500	—	13,046	9,597
2014	8,350	14,309	—	13,516	9,143

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

GEORGIA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2016 , 2015 , AND 2014
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2016	$ 2,147	$ 14,476	$ —	$ 13,787	$ 2,836
2015	6,076	16,862	—	20,791	2,147
2014	5,074	24,141	—	23,139	6,076

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

GULF POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2016 , 2015 , AND 2014
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions		Deductions (Note)	Balance at End of Period
		Charged to Income	Charged to Other Accounts		
Provision for uncollectible accounts					
2016	$ 775	$ 2,946	$ —	$ 2,989	$ 732
2015	2,087	2,041	—	3,353	775
2014	1,131	4,304	—	3,348	2,087

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

MISSISSIPPI POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2016 , 2015 , AND 2014
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2016	$ 287	$ 1,295	$ —	$ 1,088	$ 494
2015 [(*)]	825	(1,994)	—	(1,456)	287
2014	3,018	562	—	2,755	825

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

(*) The refund ordered by the Mississippi PSC pursuant to the 2015 Mississippi Supreme Court decision relative to Mirror CWIP involved refunding all billed amounts to all historical customers and included an interest component. The refund of approximately $371 million in 2015 was of sufficient magnitude to resolve most past due amounts beyond 30 days aged receivables, accounting for the negative provision of $(2.0) million where risk of collectibility was offset by applying the refund to past due amounts. It was also of sufficient size to offset amounts previously written off in the 2012-2015 time frame, accounting for the net recoveries of $1.5 million .

For more information regarding the 2015 decision of the Mississippi Supreme Court related to the Mirror CWIP refund in fourth quarter 2015, see Note 3 to the financial statement of Mississippi Power under "Integrated Coal Gasification Combined Cycle – 2013 MPSC Rate Order" in Item 8 herein.

SOUTHERN COMPANY GAS AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE SUCCESSOR PERIOD OF JULY 1, 2016 THROUGH DECEMBER 31, 2016
AND THE PREDECESSOR PERIODS OF JANUARY 1, 2016 THROUGH JUNE 30, 2016
AND THE YEARS ENDED DECEMBER 31, 2015 AND 2014
(Stated in Thousands of Dollars)

		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Successor – December 31, 2016					
Provision for uncollectible accounts	$ 37,663	$ 9,500	$ (1,257)	$ 18,590	$ 27,316
Income tax valuation	19,182	—	—	—	19,182
Predecessor – June 30, 2016					
Provision for uncollectible accounts	$ 29,142	$ 15,976	$ 1,608	$ 9,063	$ 37,663
Income tax valuation	19,182	—	—	—	19,182
Predecessor – 2015					
Provision for uncollectible accounts	$ 35,069	$ 27,050	$ 3,017	$ 35,994	$ 29,142
Income tax valuation	19,637	—	—	455	19,182
Predecessor – 2014					
Provision for uncollectible accounts	$ 29,261	$ 54,790	$ 1,414	$ 50,396	$ 35,069
Income tax valuation	22,329	—	—	2,692	19,637

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

EXHIBIT INDEX

The exhibits below with an asterisk (*) preceding the exhibit number are filed herewith. The remaining exhibits have previously been filed with the SEC and are incorporated herein by reference. The exhibits marked with a pound sign (#) are management contracts or compensatory plans or arrangements required to be identified as such by Item 15 of Form 10-K.

(2) Plan of acquisition, reorganization, arrangement, liquidation or succession

Southern Company

(a) 1 — Agreement and Plan of Merger by and among Southern Company, AMS Corp., and Southern Company Gas, dated August 23, 2015. (Designated in Form 8-K dated August 23, 2015, File No. 1-3526, as Exhibit 2.1.)

Southern Company Gas

(g) 1 — Agreement and Plan of Merger by and among Southern Company, AMS Corp., and Southern Company Gas, dated August 23, 2015. See Exhibit 2(a)1 herein.

(g) 2 — Purchase and Sale Agreement, dated as of July 10, 2016, among Kinder Morgan SNG Operator LLC, Southern Natural Gas Company, L.L.C., and Southern Company.(Designated in Form 8-K dated August 31, 2016, File No. 1-14174, as Exhibit 2.1a.)

(g) 3 — Assignment, Assumption and Novation of Purchase and Sale Agreement, dated as of August 31, 2016, between Southern Company and Evergreen Enterprise Holdings LLC.(Designated in Form 8-K dated August 31, 2016, File No. 1-14174, as Exhibit 2.1b.)

(3) Articles of Incorporation and By-Laws

Southern Company

(a) 1 — Composite Certificate of Incorporation of Southern Company, reflecting all amendments thereto through May 26, 2016. (Designated in Registration No. 33-3546 as Exhibit 4(a), in Certificate of Notification, File No. 70-7341, as Exhibit A, in Certificate of Notification, File No. 70-8181, as Exhibit A, in Form 8-K dated May 26, 2010, File No. 1-3526, as Exhibit 3.1, and in Form 8-K dated May 25, 2016, File No. 1-3526, as Exhibit 3.1.)

(a) 2 — By-laws of Southern Company as amended effective May 25, 2016, and as presently in effect. (Designated in Form 8-K dated May 25, 2016, File No. 1-3526, as Exhibit 3.2.)

Alabama Power

(b) 1 — Charter of Alabama Power and amendments thereto through April 25, 2008. (Designated in Registration Nos. 2-59634 as Exhibit 2(b), 2-60209 as Exhibit 2(c), 2-60484 as Exhibit 2(b), 2-70838 as Exhibit 4(a)-2, 2-85987 as Exhibit 4(a)-2, 33-25539 as Exhibit 4(a)-2, 33-43917 as Exhibit 4(a)-2, in Form 8-K dated February 5, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated July 8, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated October 27, 1993, File No. 1-3164, as Exhibits 4(a) and 4(b), in Form 8-K dated November 16, 1993, File No. 1-3164, as Exhibit 4(a), in Certificate of Notification, File No. 70-8191, as Exhibit A, in Form 10-K for the year ended December 31, 1997, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated August 10, 1998, File No. 1-3164, as Exhibit 4.4, in Form 10-K for the year ended December 31, 2000, File No. 1-3164, as Exhibit 3(b)2, in Form 10-K for the year ended December 31, 2001, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated February 5, 2003, File No. 1-3164, as Exhibit 4.4, in Form 10-Q for the quarter ended March 31, 2003, File No 1-3164, as Exhibit 3(b)1, in Form 8-K dated February 5, 2004, File No. 1-3164, as Exhibit 4.4, in Form 10-Q for the quarter ended March 31, 2006, File No. 1-3164, as Exhibit 3(b)(1), in Form 8-K dated December 5, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 12, 2007, File No. 1-3164, as Exhibit 4.5, in Form 8-K dated October 17, 2007, File No. 1-3164, as Exhibit 4.5, and in Form 10-Q for the quarter ended March 31, 2008, File No. 1-3164, as Exhibit 3(b)1.)

(b) 2 — Amended and Restated By-laws of Alabama Power effective February 10, 2014, and as presently in effect. (Designated in Form 8-K dated February 10, 2014, File No 1-3164, as Exhibit 3.1.)

Georgia Power

(c)	1	—	Charter of Georgia Power and amendments thereto through October 9, 2007. (Designated in Registration Nos. 2-63392 as Exhibit 2(a)-2, 2-78913 as Exhibits 4(a)-(2) and 4(a)-(3), 2-93039 as Exhibit 4(a)-(2), 2-96810 as Exhibit 4(a)-2, 33-141 as Exhibit 4(a)-(2), 33-1359 as Exhibit 4(a)(2), 33-5405 as Exhibit 4(b)(2), 33-14367 as Exhibits 4(b)-(2) and 4(b)-(3), 33-22504 as Exhibits 4(b)-(2), 4(b)-(3) and 4(b)-(4), in Form 10-K for the year ended December 31, 1991, File No. 1-6468, as Exhibits 4(a)(2) and 4(a)(3), in Registration No. 33-48895 as Exhibits 4(b)-(2) and 4(b)-(3), in Form 8-K dated December 10, 1992, File No. 1-6468 as Exhibit 4(b), in Form 8-K dated June 17, 1993, File No. 1-6468, as Exhibit 4(b), in Form 8-K dated October 20, 1993, File No. 1-6468, as Exhibit 4(b), in Form 10-K for the year ended December 31, 1997, File No. 1-6468, as Exhibit 3(c)2, in Form 10-K for the year ended December 31, 2000, File No. 1-6468, as Exhibit 3(c)2, in Form 8-K dated June 27, 2006, File No. 1-6468, as Exhibit 3.1, and in Form 8-K dated October 3, 2007, File No. 1-6468, as Exhibit 4.5.)
(c)	2	—	By-laws of Georgia Power as amended effective November 9, 2016, and as presently in effect. (Designated in Form 8-K dated November 9, 2016, File No. 1-6468, as Exhibit 3.1.)

Gulf Power

(d)	1	—	Amended and Restated Articles of Incorporation of Gulf Power and amendments thereto through June 17, 2013. (Designated in Form 8-K dated October 27, 2005, File No. 001-31737, as Exhibit 3.1, in Form 8-K dated November 9, 2005, File No. 001-31737, as Exhibit 4.7, in Form 8-K dated October 16, 2007, File No. 001-31737, as Exhibit 4.5, and in Form 8-K dated June 10, 2013, File No. 001-31737, as Exhibit 4.7.)
(d)	2	—	By-laws of Gulf Power as amended effective November 2, 2005, and as presently in effect. (Designated in Form 8-K dated October 27, 2005, File No. 001-31737, as Exhibit 3.2.)

Mississippi Power

(e)	1	—	Articles of Incorporation of Mississippi Power, articles of merger of Mississippi Power Company (a Maine corporation) into Mississippi Power and articles of amendment to the articles of incorporation of Mississippi Power through April 2, 2004. (Designated in Registration No. 2-71540 as Exhibit 4(a)-1, in Form U5S for 1987, File No. 30-222-2, as Exhibit B-10, in Registration No. 33-49320 as Exhibit 4(b)-(1), in Form 8-K dated August 5, 1992, File No. 001-11229, as Exhibits 4(b)-2 and 4(b)-3, in Form 8-K dated August 4, 1993, File No. 001-11229, as Exhibit 4(b)-3, in Form 8-K dated August 18, 1993, File No. 001-11229, as Exhibit 4(b)-3, in Form 10-K for the year ended December 31, 1997, File No. 001-11229, as Exhibit 3(e)2, in Form 10-K for the year ended December 31, 2000, File No. 001-11229, as Exhibit 3(e)2, and in Form 8-K dated March 3, 2004, File No. 001-11229, as Exhibit 4.6.)
(e)	2	—	By-laws of Mississippi Power as amended effective October 25, 2016, and as presently in effect. (Designated in Form 8-K dated October 25, 2016, File No. 001-11229, as Exhibit 3.1)

Southern Power

(f)	1	—	Certificate of Incorporation of Southern Power Company dated January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.1.)
(f)	2	—	By-laws of Southern Power Company effective January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.2.)

Southern Company Gas

(f)	1	—	Amended and Restated Articles of Incorporation of Southern Company Gas dated July 11, 2016. (Designated in Form 8-K dated July 8, 2016, File No. 1-14174, as Exhibit 3.1.)
(f)	2	—	By-laws of Southern Company Gas effective July 11, 2016. (Designated in Form 8-K dated July 8, 2016, File No. 1-14174, as Exhibit 3.2.)

(4) Instruments Describing Rights of Security Holders, Including Indentures

With respect to each of Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and Southern Company Gas such registrant has not included any instrument with respect to long-term debt that does not exceed 10% of the total assets of such registrant and its subsidiaries. Each such registrant agrees, upon request of the SEC, to furnish copies of any or all such instruments to the SEC.

Southern Company

(a)	1	—	Senior Note Indenture dated as of January 1, 2007, between Southern Company and Wells Fargo Bank, National Association, as Trustee, and indentures supplemental thereto through May 24, 2016. (Designated in Form 8-K dated January 11, 2007, File No. 1-3526, as Exhibits 4.1 and 4.2, in Form 8-K dated March 20, 2007, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated August 13, 2008, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated May 11, 2009, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated October 19, 2009, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated September 13, 2010, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated August 16, 2011, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated August 21, 2013, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated August 19, 2014, File No. 1-3526, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated June 9, 2015, File No. 1-3526, as Exhibit 4.2, and in Form 8-K dated May 19, 2016, File No. 1-3526, as Exhibits 4.2(a), 4.2(b), 4.2(c), 4.2(d), 4.2(e), 4.2(f) and 4.2(g).)
(a)	2	—	Subordinated Note Indenture dated as of October 1, 2015, between The Southern Company and Wells Fargo Bank, National Association, as Trustee, and indentures supplemental thereto through December 8, 2016. (Designated in Form 8-K dated October 1, 2015, File No. 1-3526, as Exhibits 4.3 and 4.4, in Form 8-K dated September 12, 2016, File No. 1-3526, as Exhibit 4.4, and in Form 8-K dated December 5, 2016, File No. 1-3526, as Exhibit 4.4.)

Alabama Power

(b)	1	—	Subordinated Note Indenture dated as of January 1, 1997, between Alabama Power and Regions Bank, as Successor Trustee, and indentures supplemental thereto through October 2, 2002. (Designated in Form 8-K dated January 9, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 18, 1999, File No. 1-3164, as Exhibit 4.2, and in Form 8-K dated September 26, 2002, File No. 3164, as Exhibits 4.9-A and 4.9-B.)

(b)	2	—	Senior Note Indenture dated as of December 1, 1997, between Alabama Power and Regions Bank, as Successor Trustee, and indentures supplemental thereto through January 13, 2016. (Designated in Form 8-K dated December 4, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 20, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 17, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 11, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 8, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 16, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 7, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 28, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 12, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 19, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 13, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 21, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 11, 2000, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 22, 2001, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated June 21, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated October 16, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated November 20, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated December 6, 2002, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 11, 2003, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 12, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 15, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 1, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 14, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 10, 2004, File No. 1-3164, as Exhibit 4.2 in Form 8-K dated April 7, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 19, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 9, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated March 8, 2005, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 11, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 13, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 1, 2006, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 9, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated June 7, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 30, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 4, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 11, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated December 4, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 8, 2008, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 14, 2008, File No. 1-3164 as Exhibit 4.2, in Form 8-K dated February 26, 2009, File No. 1-3164 as Exhibit 4.2, in Form 8-K dated September 27, 2010, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated March 3, 2011, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 18, 2011, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated January 10, 2012, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 9, 2012, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 27, 2012, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated December 3, 2013, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 20, 2014, File No. 1-3164, as Exhibit 4.6, in Form 8-K dated March 5, 2015, File No. 1-3164, as Exhibit 4.6, in Form 8-K dated April 9, 2015, File No. 1-3164, as Exhibit 4.6(b), and in Form 8-K dated January 8, 2016, File No. 1-3164, as Exhibit 4.6.)
(b)	3	—	Amended and Restated Trust Agreement of Alabama Power Capital Trust V dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.12-B.)
(b)	4	—	Guarantee Agreement relating to Alabama Power Capital Trust V dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.16-B.)

Georgia Power

(c)	1	—	Senior Note Indenture dated as of January 1, 1998, between Georgia Power and Wells Fargo Bank, National Association, as Successor Trustee, and indentures supplemental thereto through March 8, 2016. (Designated in Form 8-K dated January 21, 1998, File No. 1-6468, as Exhibits 4.1 and 4.2, in Forms 8-K each dated November 19, 1998, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 3, 1999, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated February 15, 2000, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated January 26, 2001, File No. 1-6469 as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated February 16, 2001, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated May 1, 2001, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 27, 2002, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 15, 2002, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 13, 2003, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 21, 2003, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated April 10, 2003, File No. 1-6468, as Exhibits 4.1, 4.2 and 4.3, in Form 8-K dated September 8, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated September 23, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated January 12, 2004, File No. 1-6468, as Exhibits 4.1 and 4.2, in Form 8-K dated February 12, 2004, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated August 11, 2004, File No. 1-6468, as Exhibits 4.1 and 4.2, in Form 8-K dated January 13, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated April 12, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated November 30, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated December 8, 2006, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 6, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 4, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 18, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated July 10, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated August 24, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 29, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 12, 2008, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 5, 2008, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 12, 2008, File No. 1-6468, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated February 4, 2009, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated December 8, 2009, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 9, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated May 24, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated August 26, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated September 20, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated January 13, 2011, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated April 12, 2011, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 29, 2012, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated May 8, 2012, File No. 1-6468, as Exhibit 4.2(b), in Form 8-K dated August 7, 2012, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 8, 2012, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 12, 2013, File No. 1-6468, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated August 12, 2013, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated December 1, 2015, File No. 1-6468, as Exhibit 4.2, and in Form 8-K dated March 2, 2016, File No. 1-6468, as Exhibits 4.2(a) and 4.2(b).)
(c)	2	—	Loan Guarantee Agreement between Georgia Power and the DOE dated as of February 20, 2014, Amendment No. 1 thereto dated as of June 4, 2015, and Amendment No. 2 thereto dated as of March 9, 2016. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.1, in Form 10-Q for the quarter ended June 30, 2015, File No. 1-6468, as Exhibit 10(c)1, and in Form 10-Q for the quarter ended March 31, 2016, File No. 1-6468, as Exhibit 4(c)3.)
(c)	3	—	Note Purchase Agreement among Georgia Power, the DOE, and the Federal Financing Bank dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.2.)
(c)	4	—	Future Advance Promissory Note dated February 20, 2014 made by Georgia Power to the FFB. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.3.)
(c)	5	—	Deed to Secure Debt, Security Agreement and Fixture Filing between Georgia Power and PNC Bank, National Association, doing business as Midland Loan Services Inc., a division of PNC Bank, National Association dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.4.)
(c)	6	—	Owners Consent to Assignment and Direct Agreement and Amendment to Plant Alvin W. Vogtle Additional Units Ownership Participation Agreement by and among Georgia Power, OPC, MEAG Power, and Dalton dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.5.)

Gulf Power

(d)	1	—	Senior Note Indenture dated as of January 1, 1998, between Gulf Power and Wells Fargo Bank, National Association, as Successor Trustee, and indentures supplemental thereto through September 23, 2014. (Designated in Form 8-K dated June 17, 1998, File No. 0-2429, as Exhibits 4.1 and 4.2, in Form 8-K dated August 17, 1999, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated July 31, 2001, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated October 5, 2001, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated January 18, 2002, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated March 21, 2003, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated July 10, 2003, File No. 001-31737, as Exhibits 4.1 and 4.2, in Form 8-K dated September 5, 2003, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated April 6, 2004, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated September 13, 2004, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated August 11, 2005, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated October 27, 2005, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated November 28, 2006, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated June 5, 2007, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated June 22, 2009, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated April 6, 2010, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated September 9, 2010, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated May 12, 2011, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated May 15, 2012, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated June 10, 2013, File No. 001-31737, as Exhibit 4.2, and in Form 8-K dated September 16, 2014, File No. 001-31737, as Exhibit 4.2.)

Mississippi Power

(e)	1	—	Senior Note Indenture dated as of May 1, 1998, between Mississippi Power and Wells Fargo Bank, National Association, as Successor Trustee, and indentures supplemental thereto through March 9, 2012. (Designated in Form 8-K dated May 14, 1998, File No. 001-11229, as Exhibits 4.1, 4.2(a) and 4.2(b), in Form 8-K dated March 22, 2000, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 12, 2002, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated April 24, 2003, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 3, 2004, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated June 24, 2005, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated November 8, 2007, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated November 14, 2008, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 3, 2009, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated October 11, 2011, File No. 001-11229, as Exhibits 4.2(a) and 4.2(b), and in Form 8-K dated March 5, 2012, File No. 001-11229, as Exhibit 4.2(b).)
(e)	2	—	Term Loan Agreement among Mississippi Power and the lenders identified therein, dated as of March 8, 2016. (Designated in Form 10-Q for the quarter ended March 31, 2016, File No. 001-11229, as Exhibit 4(e)1.)

Southern Power

(f)	1	—	Senior Note Indenture dated as of June 1, 2002, between Southern Power Company and Wells Fargo Bank, National Association, as Successor Trustee, and indentures supplemental thereto through November 16, 2016. (Designated in Registration No. 333-98553 as Exhibits 4.1 and 4.2, in Form 10-Q for the quarter ended June 30, 2003, File No. 333-98553, as Exhibit 4(g)1, in Form 8-K dated November 13, 2006, File No. 333-98553, as Exhibit 4.2, in Form 8-K dated September 14, 2011, File No. 333-98553, as Exhibit 4.4, in Form 8-K dated July 10, 2013, File No. 333-98553, as Exhibit 4.4, in Form 8-K dated May 14, 2015, File No. 333-98553, as Exhibits 4.4(a) and 4.4(b), in Form 8-K dated November 12, 2015, File No. 333-98553, as Exhibits 4.4(a) and 4.4(b), in Form 8-K dated June 13, 2016, File No. 001-37803, as Exhibits 4.4(a) and 4.4(b), in Form 10-Q for the quarter ended September 30, 2016, File No. 001-37803, as Exhibits 4(f)1 and 4(f)2, and in Form 8-K dated November 10, 2016, File No. 001-37803, as Exhibits 4.4(a), 4.4(b), and 4.4(c).)

Southern Company Gas

(g)	1	—	Indenture dated February 20, 2001 between AGL Capital Corporation, AGL Resources Inc. and The Bank of New York, as Trustee. (Designated in Form S-3, File No. 333-69500, as Exhibit 4.2.)

	(g)	2	—	Southern Company Gas Capital Corporation's 6.00% Senior Note s due 2034, 6 . 375% Senior Notes due 2016, 5.25% Senior Notes due 2019, Form of 3 . 50% Senior Note s due 2021, 5.875% Senior Notes due 2041, Form of Serie s A Senior Note s due 2016, Form of Series B Senior Notes due 2018, 4.40% Senior Note s due 2043, 3.875% Senior Note s due 2025, 3.250% Senior Notes due 2026, Form of 2.450% Senior Note due October 1, 2023, and Form of 3.950% Senior Note due October 1, 2046. (Designated in Form 8-K dated September 22, 2004, File No. 1-14174, as Exhibit 4.1, in Form 8-K dated December 11, 2007, File No. 1-14174, as Exhibit 4.1, in Form 8-K dated August 5, 2009, File No. 1-14174, as Exhibit 4.1, in Form 8-K dated September 15, 2011, File No. 1-14174, as Exhibit 4.1, in Form 8-K dated March 16, 2011, File No. 1-14174, as Exhibit 4.1, in Form 8-K dated August 31, 2011, File No. 1-14174, as Exhibits 4.1 and 4.2, in Form 8-K dated May 13, 2013, File No. 1-14174, as Exhibit 4.2, in Form 8-K dated November 13, 2015, File No. 1-14174, as Exhibit 4.2, in Form 8-K dated May 13, 2016, File No. 1-14174, as Exhibit 4.2, and in Form 8-K dated September 8, 2016, File No. 1-14174, as Exhibits 4.1(a) and 4.1(b), respectively.)
	(g)	3	—	Southern Company Gas' Guarant e e related to the 6.00% Senior Notes due 2034 , Guarantee related to the 6.375% Senior Notes due 2016, Guarantee related to the 5.25% Senior Notes due 2019 , Guarantee related to the 5.875% Senior Notes due 2041, Form of Guarantee related to the 3.50% Senior Notes due 2021, Guarantee relat e d to the 4.40% Senior Notes due 2043, Guarantee related to the 3.875% Senior Notes due 2025, Guarantee related to the 3.250% Senior Notes due 2026, Form of Guarantee related to the 2.450% Senior Notes due October 1, 2023, and Form of Guarantee related to the 3.950% Senior Notes due October 1, 2046. (Designated in Form 8-K dated September 22, 2004, File No. 1-14174, as Exhibit 4.3, in Form 8-K dated December 11, 2007, File No. 1-14174, as Exhibit 4.2, in Form 8-K dated August 5, 2009, File No. 1-14174, as Exhibit 4.2, in Form 8-K dated March 16, 2011, File No. 1-14174, as Exhibit 4.2, in Form 8-K dated September 15, 2011, File No. 1-14174, as Exhibit 4.2, in Form 8-K dated May 13, 2013, File No. 1-14174, as Exhibit 4.3, in Form 8-K dated November 13, 2015, File No. 1-14174, as Exhibit 4.3, in Form 8-K dated May 13, 2016, File No. 1-14174, as Exhibit 4.3, and in Form 8-K dated September 8, 2016, File No. 1-14174, as Exhibits 4.3(a) and 4.3(b), respectively.)
	(g)	4	—	Indenture dated December 1, 1989 of Atlanta Gas Light Company and First Supplemental Indenture thereto dated March 16, 1992. (Designated in Form S-3, File No. 33-32274, as Exhibit 4(a) and in Form S-3, File No. 33-46419, as Exhibit 4(a).)
	(g)	5	—	Indenture of Commonwealth Edison Company to Continental Illinois National Bank and Trust Company of Chicago, Trustee, dated as of January 1, 1954, Indenture of Adoption of Northern Illinois Gas Company to Continental Illinois National Bank and Trust Company of Chicago, Trustee, dated February 9, 1954, and certain indentures supplemental thereto. (Designated in Form 10-K for the year ended December 31, 1995, File No. 1-7296, as Exhibits 4.01 and 4.02, in Registration No. 2-56578 as Exhibits 2.21 and 2.25, in Form 10-Q for the quarter ended June 30, 1996, File No. 1-7296, as Exhibit 4.01, in Form 10-K for the year ended December 31, 1997, File No. 1-7296, as Exhibit 4.19, in Form 10-K for the year ended December 31, 2003, File No. 1-7296, as Exhibits 4.09, 4.10 and 4.11, in Form 10-K for the year ended December 31, 2006, File No. 1-7296, as Exhibit 4.11, in Form 10-Q for the quarter ended September 30, 2008, File No. 1-7296, as Exhibit 4.01, in Form 10-Q for the quarter ended June 31, 2009, File No. 1-7296, as Exhibit 4.01, and in Form 10-Q for the quarter ended September 30, 2012, File No. 1-7296, as Exhibit 4.)
*	(g)	6	—	Supplemental Indenture dated June 16, 2016 of Northern Illinois Gas Company to The Bank of New York Mellon Trust Company, N.A., under Indenture dated January 1, 1954.

(10) Material Contracts

Southern Company

#	(a)	1	—	Southern Company 2011 Omnibus Incentive Compensation Plan effective May 25, 2011. (Designated in Form 8-K dated May 25, 2011, File No. 1-3526, as Exhibit 10.1.)
#	(a)	2	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. (Designated in Form 10-Q for the quarter ended March 31, 2011, File No. 1-3526, as Exhibit 10(a)3.)
#	(a)	3	—	Deferred Compensation Plan for Outside Directors of The Southern Company, Amended and Restated effective January 1, 2008 and First Amendment thereto effective April 1, 2015. (Designated in Form 10-K for the year ended December 31, 2007, File No. 1-3526, as Exhibit 10(a)3 and in Form 10-Q for the quarter ended June 30, 2015, File No. 1-3526, as Exhibit 10(a)1.)

#	(a)	4	—	Southern Company Deferred Compensation Plan, Amended and Restated as of January 1, 2009, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective October 29, 2014. (Designated in Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)4, in Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)5, and in Form 10-K for the year ended December 31, 2015, File No. 1-3526, as Exhibit 10(a)21.)
#	(a)	5	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective June 30, 2016. (Designated in Form 10-Q for the quarter ended June 30, 2016, File No. 1-3526, as Exhibit 10(a)1.)
#	(a)	6	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of June 30, 2016. (Designated in Form 10-Q for the quarter ended June 30, 2016, File No. 1-3526, as Exhibit 10(a)2.)
#	(a)	7	—	The Southern Company Change in Control Benefits Protection Plan (an amendment and restatement of The Southern Company Change in Control Benefit Plan Determination Policy), effective December 31, 2008. (Designated in Form 8-K dated December 31, 2008, File No. 1-3526, as Exhibit 10.1.)
#	(a)	8	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern LINC, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. (Designated in Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)103 and in Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)16.)
#	(a)	9	—	Deferred Stock Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. (Designated in Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)104 and in Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)18.)
#	(a)	10	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. (Designated in Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)92 and in Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)20.)
#	(a)	11	—	Southern Company Senior Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008, First Amendment thereto effective October 19, 2009, and Second Amendment thereto effective February 22, 2011. (Designated in Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)23, in Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)22, and in Form 10-K for the year ended December 31, 2010, File No. 1-3526, as Exhibit 10(a)16.)
#	(a)	12	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. (Designated in Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)24 and in Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)24.)
#	(a)	13	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. (Designated in Form 10-K for the year ended December 31, 2014, File No. 1-3526, as Exhibit 10(a)17).
#	(a)	14	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries effective June 1, 2015. (Designated in Definitive Proxy Statement filed April 10, 2015, File No. 1-3526, as Appendix A.)
	(a)	15	—	Commitment Letter dated August 23, 2015. (Designated in Form 8-K dated August 23, 2015, File No. 1-3526, as Exhibit 10.1.)
	(a)	16	—	Bridge Credit Agreement dated as of September 30, 2015, among Southern Company, as the Borrower, the Lenders identified therein, and Citibank, N.A., as Administrative Agent. (Designated in Form 8-K dated September 30, 2015, File No. 1-3526, as Exhibit 10.1.)
# *	(a)	17	—	Deferred Compensation Agreement between Southern Company, SCS, Alabama Power, and Mark A. Crosswhite, effective July 30, 2008.

# *	(a)	18	—	First Amendment to The Southern Company Supplemental Executive Retirement Plan effective January 1, 2017.
# *	(a)	19	—	First Amendment to The Southern Company Supplemental Benefit Plan effective January 1, 2017.
Alabama Power				
	(b)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. (Designated in Form 10-Q for the quarter ended March 31, 2007, File No. 1-3164, as Exhibit 10(b)5.)
#	(b)	2	—	Southern Company 2011 Omnibus Incentive Compensation Plan effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(b)	3	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(b)	4	—	Southern Company Deferred Compensation Plan, Amended and Restated as of January 1, 2009, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective October 29, 2014. See Exhibit 10(a)4 herein.
#	(b)	5	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective June 30, 2016. See Exhibit 10(a)5 herein.
#	(b)	6	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of June 30, 2016. See Exhibit 10(a)6 herein.
#	(b)	7	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)12 herein.
#	(b)	8	—	Deferred Compensation Plan for Outside Directors of Alabama Power Company, Amended and Restated effective January 1, 2008 and First Amendment thereto effective June 1, 2015. (Designated in Form 10-Q for the quarter ended June 30, 2008, File No. 1-3164, as Exhibit 10(b)1 and in Form 10-Q for the quarter ended June 30, 2015, File No. 1-3164, as Exhibit 10(b)1.)
#	(b)	9	—	The Southern Company Change in Control Benefits Protection Plan (an amendment and restatement of The Southern Company Change in Control Benefit Plan Determination Policy), effective December 31, 2008. See Exhibit 10(a)7 herein.
#	(b)	10	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern LINC, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)8 herein.
#	(b)	11	—	Deferred Stock Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)9 herein.
#	(b)	12	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.
#	(b)	13	—	Southern Company Senior Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008, First Amendment thereto effective October 19, 2009, and Second Amendment thereto effective February 22, 2011. See Exhibit 10(a)11 herein.
#	(b)	14	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)13 herein.
#	(b)	15	—	Deferred Compensation Agreement between Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and SCS and Philip C. Raymond dated September 15, 2010. (Designated in Form 10-Q for the quarter ended September 30, 2010, File No. 1-3164, as Exhibit 10(b)2.)
#	(b)	16	—	Deferred Compensation Agreement between Southern Company, SCS, Alabama Power, and Mark A. Crosswhite, effective July 30, 2008. See Exhibit 10(a)17 herein.
#	(b)	17	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries effective June 1, 2015. See Exhibit 10(a)14 herein.

#	(b)	18	—	Employment Agreement between Alabama Power and Steven R. Spencer effective April 1, 2016. (Designated in Form 10-K for the year ended December 31, 2015, File No. 1-3164, as Exhibit 10(b)21.
#	(b)	19	—	First Amendment to The Southern Company Supplemental Executive Retirement Plan effective January 1, 2017. See Exhibit 10(a)18 herein.
#	(b)	20	—	First Amendment to The Southern Company Supplemental Benefit Plan effective January 1, 2017. See Exhibit 10(a)19 herein.
Georgia Power				
	(c)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein.
	(c)	2	—	Revised and Restated Integrated Transmission System Agreement dated as of November 12, 1990, between Georgia Power and OPC. (Designated in Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(g).)
	(c)	3	—	Revised and Restated Integrated Transmission System Agreement between Georgia Power and Dalton dated as of December 7, 1990. (Designated in Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(gg).)
	(c)	4	—	Revised and Restated Integrated Transmission System Agreement between Georgia Power and MEAG Power dated as of December 7, 1990. (Designated in Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(hh).)
#	(c)	5	—	Southern Company 2011 Omnibus Incentive Compensation Plan effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(c)	6	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(c)	7	—	Southern Company Deferred Compensation Plan, Amended and Restated as of January 1, 2009, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective October 29, 2014. See Exhibit 10(a)4 herein.
#	(c)	8	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective June 30, 2016. See Exhibit 10(a)5 herein.
#	(c)	9	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of June 30, 2016. See Exhibit 10(a)6 herein.
#	(c)	10	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)12 herein.
#	(c)	11	—	Deferred Compensation Plan For Outside Directors of Georgia Power Company, Amended and Restated Effective January 1, 2008 and First Amendment thereto effective April 1, 2015. (Designated in Form 10-K for the year ended December 31, 2007, File No. 1-6468, as Exhibit 10(c)12 and in Form 10-Q for the quarter ended March 31, 2015, File No. 1-6468, as Exhibit 10(c)2.)
#	(c)	12	—	The Southern Company Change in Control Benefits Protection Plan (an amendment and restatement of The Southern Company Change in Control Benefit Plan Determination Policy), effective December 31, 2008. See Exhibit 10(a)7 herein.
#	(c)	13	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern LINC, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)8 herein.
#	(c)	14	—	Deferred Stock Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)9 herein.
#	(c)	15	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.

#	(c)	16	—	Southern Company Senior Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008, First Amendment thereto effective October 19, 2009, and Second Amendment thereto effective February 22, 2011. See Exhibit 10(a)11 herein.
	(c)	17	—	Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for OPC, MEAG Power, and Dalton, as owners, and a consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc., as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site, Amendment No. 1 thereto dated as of December 11, 2009, Amendment No. 2 thereto dated as of January 15, 2010, Amendment No. 3 thereto dated as of February 23, 2010, Amendment No. 4 thereto dated as of May 2, 2011, Amendment No. 5 thereto dated as of February 7, 2012, Amendment No. 6 thereto dated as of January 23, 2014, Amendment No. 7 thereto dated as of January 6, 2016, and Amendment No. 8 thereto dated as of April 20, 2016. (Georgia Power requested confidential treatment for certain portions of these documents pursuant to applications for confidential treatment sent to the SEC. Georgia Power omitted such portions from the filings and filed them separately with the SEC.) (Designated in Form 10-Q/A for the quarter ended June 30, 2008, File No. 1-6468, as Exhibit 10(c)1, in Form 10-K for the year ended December 31, 2009, File No. 1-6468, as Exhibit 10(c)29, in Form 10-Q for the quarter ended March 31, 2010, File No. 1-6468, as Exhibits 10(c)1 and 10(c)2, in Form 10-Q for the quarter ended June 30, 2011, File No. 1-6468, as Exhibit 10(c)2, in Form 10-Q for the quarter ended March 31, 2012, File No. 1-6468, as Exhibit 10(c)2, in Form 10-Q for the quarter ended March 31, 2014, File No. 1-6468, as Exhibit 10(c)2, in Form 10-K for the year ended December 31, 2015, File No. 1-6468, as Exhibit 10(c)25, and in Form 10-Q for the quarter ended June 30, 2016, File No. 1-6468, as Exhibit 10(c)3.)
#	(c)	18	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)13 herein.
#	(c)	19	—	Deferred Compensation Agreement between Southern Company, Southern Company Services, Inc., and John L. Pemberton, effective October 10, 2008. (Designated in Form 10-Q for the quarter ended March 31, 2015, File No. 1-6468, as Exhibit 10(c)3.)
#	(c)	20	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries effective June 1, 2015. See Exhibit 10(a)14 herein.
#	(c)	21	—	First Amendment to The Southern Company Supplemental Executive Retirement Plan effective January 1, 2017. See Exhibit 10(a)18 herein.
#	(c)	22	—	First Amendment to The Southern Company Supplemental Benefit Plan effective January 1, 2017. See Exhibit 10(a)19 herein.
Gulf Power				
	(d)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein.
#	(d)	2	—	Southern Company 2011 Omnibus Incentive Compensation Plan effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(d)	3	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(d)	4	—	Southern Company Deferred Compensation Plan, Amended and Restated as of January 1, 2009, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective October 29, 2014. See Exhibit 10(a)4 herein.
#	(d)	5	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of June 30, 2016. See Exhibit 10(a)6 herein.
#	(d)	6	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective June 30, 2016 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)12 herein.
#	(d)	7	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective June 30, 2016. See Exhibit 10(a)5 herein.
#	(d)	8	—	Deferred Compensation Plan For Outside Directors of Gulf Power Company, Amended and Restated effective January 1, 2008 and First Amendment thereto effective April 1, 2015. (Designated in Form 10-Q for the quarter ended March 31, 2008, File No. 0-2429, as Exhibit 10(d)1 and in Form 10-Q for the quarter ended June 30, 2015, File No. 001-11229, as Exhibit 10(d)1.)
#	(d)	9	—	The Southern Company Change in Control Benefits Protection Plan (an amendment and restatement of The Southern Company Change in Control Benefit Plan Determination Policy), effective December 31, 2008. See Exhibit 10(a)7 herein.

#	(d)	10	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern LINC, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)8 herein.
#	(d)	11	—	Deferred Stock Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)9 herein.
#	(d)	12	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.
#	(d)	13	—	Southern Company Senior Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008, First Amendment thereto effective October 19, 2009, and Second Amendment thereto effective February 22, 2011. See Exhibit 10(a)11 herein.
#	(d)	14	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)13 herein.
#	(d)	15	—	Deferred Compensation Agreement between Southern Company, Georgia Power, Gulf Power, and Southern Nuclear and Bentina C. Terry dated August 1, 2010. (Designated in Form 10-Q for the quarter ended September 30, 2010, File No. 001-31737, as Exhibit 10(d)2.)
#	(d)	16	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries effective June 1, 2015. See Exhibit 10(a)14 herein.
#	(d)	17	—	First Amendment to The Southern Company Supplemental Executive Retirement Plan effective January 1, 2017. See Exhibit 10(a)18 herein.
#	(d)	18	—	First Amendment to The Southern Company Supplemental Benefit Plan effective January 1, 2017. See Exhibit 10(a)19 herein.
Mississippi Power				
	(e)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein.
	(e)	2	—	Transmission Facilities Agreement dated February 25, 1982, Amendment No. 1 dated May 12, 1982 and Amendment No. 2 dated December 6, 1983, between Entergy Corporation (formerly Gulf States) and Mississippi Power. (Designated in Form 10-K for the year ended December 31, 1981, File No. 001-11229, as Exhibit 10(f), in Form 10-K for the year ended December 31, 1982, File No. 001-11229, as Exhibit 10(f)(2), and in Form 10-K for the year ended December 31, 1983, File No. 001-11229, as Exhibit 10(f)(3).)
#	(e)	3	—	Southern Company 2011 Omnibus Incentive Compensation Plan effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(e)	4	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(e)	5	—	Southern Company Deferred Compensation Plan, Amended and Restated as of January 1, 2009, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective October 29, 2014. See Exhibit 10(a)4 herein.
#	(e)	6	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of June 30, 2016. See Exhibit 10(a)6 herein.
#	(e)	7	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)12 herein.
#	(e)	8	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective June 30, 2016. See Exhibit 10(a)5 herein.
#	(e)	9	—	Deferred Compensation Plan for Outside Directors of Mississippi Power Company, Amended and Restated effective January 1, 2008 and First Amendment thereto effective April 1, 2015. (Designated in Form 10-Q for the quarter ended March 31, 2008, File No. 001-11229 as Exhibit 10(e)1 and in Form 10-Q for the quarter ended June 30, 2015, File No. 001-11229 as Exhibit 10(e)1.)

#	(e)	10	—	The Southern Company Change in Control Benefits Protection Plan (an amendment and restatement of The Southern Company Change in Control Benefit Plan Determination Policy), effective December 31, 2008. See Exhibit 10(a)7 herein.
#	(e)	11	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern LINC, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)8 herein.
#	(e)	12	—	Deferred Stock Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)9 herein.
#	(e)	13	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.
#	(e)	14	—	Southern Company Senior Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008, First Amendment thereto effective October 19, 2009, and Second Amendment thereto effective February 22, 2011. See Exhibit 10(a)11 herein.
	(e)	15	—	Cooperative Agreement between the DOE and SCS dated as of December 12, 2008. (Designated in Form 10-K for the year ended December 31, 2008, File No. 001-11229, as Exhibit 10(e)22.) (Mississippi Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Mississippi Power omitted such portions from this filing and filed them separately with the SEC.)
#	(e)	16	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)13 herein.
#	(e)	17	—	Amended Deferred Compensation Agreement effective December 31, 2008 between Southern Company, SCS, Georgia Power, Gulf Power and G. Edison Holland, Jr. (Designated in Form 10-Q for the quarter ended March 31, 2011, File No. 001-11229, as Exhibit 10(a)2.)
#	(e)	18	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries effective June 1, 2015. See Exhibit 10(a)14 herein.
#	(e)	19	—	Letter Agreement between Mississippi Power and Emile J. Troxclair III dated December 11, 2014. (Designated in Form 10-Q for the quarter ended March 31, 2016, File No. 001-11229, as Exhibit 10(e)1.)
#	(e)	20	—	Performance Award Agreement between Southern Company Services, Inc. and Emile J. Troxclair III effective as of January 3, 2015. (Designated in Form 10-Q for the quarter ended March 31, 2016, File No. 001-11229, as Exhibit 10(e)2.)
*	(e)	21	—	Promissory Note dated November 10, 2015 between Mississippi Power and Southern Company.
*	(e)	22	—	Amended and Restated Promissory Note dated December 22, 2015 between Mississippi Power and Southern Company.
*	(e)	23	—	Promissory Note dated January 28, 2016 between Mississippi Power and Southern Company.
#	(e)	24	—	First Amendment to The Southern Company Supplemental Executive Retirement Plan effective January 1, 2017. See Exhibit 10(a)18 herein.
#	(e)	25	—	First Amendment to The Southern Company Supplemental Benefit Plan effective January 1, 2017. See Exhibit 10(a)19 herein.

Southern Power

	(f)	1	—	Service contract dated as of January 1, 2001, between SCS and Southern Power Company. (Designated in Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)(2).)
	(f)	2	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein.

	(f)	3	—	Amended and Restated Engineering, Procurement and Construction Agreement between Desert Stateline LLC and First Solar Electric (California), Inc. dated as of August 31, 2015. (Southern Power has requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Southern Power omitted such portions from the filing and filed them separately with the SEC.)(Designated in Form 10-Q for the quarter ended September 30, 2015, File No. 333-98533, as Exhibit 10(e)1.)

Southern Company Gas

#	(g)	1	—	Form of Director Indemnification Agreement dated April 28, 2004. (Designated in Form 10-Q for the quarter ended June 30, 2004, File No. 1-14174, as Exhibit 10.3.)
#	(g)	2	—	Nonqualified Savings Plan as amended and restated as of January 1, 2009, First Amendment effective December 18, 2009, Second Amendment effective January 1, 2013, and Third Amendment effective January 1, 2013. (Designated in Form 10-K for the year ended December 31, 2008, File No. 1-14174, as Exhibit 10.1.av and in Form 10-K for the year ended December 31, 2013, File No. 1-14174, as Exhibits 10.1.aa, 10.1.ab, and 10.1.ac.)
#	(g)	3	—	Excess Benefit Plan as amended and restated as of January 1, 2009. (Designated in Form 10-K for the year ended December 31, 2008, File No. 1-14174, as Exhibit 10.1.az.)
	(g)	4	—	Note Purchase Agreement dated August 31, 2011. (Designated in Form 8-K dated August 31, 2011, File No. 1-14174, as Exhibit 10.1.)
	(g)	5	—	Final Allocation Agreement dated January 3, 2008. (Designated in Form 10-K for the year ended December 31, 2007, File No. 1-14174, as Exhibit 10.15.)
	(g)	6	—	Second Amended and Restated Limited Liability Company Agreement of SouthStar Energy Services LLC dated September 6, 2013 by and between Georgia Natural Gas Company and Piedmont Energy Company. (Designated in Form 10-Q for the quarter ended September 30, 2013, File No. 1-14174, as Exhibit 10.)
	(g)	7	—	Credit Agreement dated as of December 15, 2011 and First Amendment thereto dated as of February 26, 2013. Designated in Form 8-K dated December 9, 2011, File No. 1-14174, as Exhibit 10.1 and in Form 10-Q for the quarter ended June 30, 2015, File No. 1-14174, as Exhibit 10.2.)
	(g)	8	—	Amended and Restated Credit Agreement dated as of November 10, 2011. (Designated in Form 8-K dated November 10, 2011, File No. 1-14174, as Exhibit 10.1.)
	(g)	9	—	Second Amendment and Extension Agreement dated as of October 30, 2015. (Designated in Form 8-K dated October 30, 2015, File No. 1-14174, as Exhibit 10.1.)
	(g)	10	—	Guarantee Agreement dated as of November 10, 2011. (Designated in Form 8-K dated November 10, 2011, File No. 1-14174, as Exhibit 10.2.)
	(g)	11	—	Bank Rate Mode Covenants Agreement, dated as of February 26, 2013 and First Amendment to Bank Rate Mode Covenants Agreement dated as of October 30, 2015. (Designated in Form 8-K dated February 26, 2013, File No. 1-14174, as Exhibit 10.1 and in Form 8-K dated October 30, 2015, File No. 1-14174, as Exhibit 10.3.)
	(g)	12	—	Loan Agreement dated as of February 1, 2013. (Designated in Form 8-K dated March 1, 2013, File No. 1-14174, as Exhibit 10.2.)
	(g)	13	—	Loan Agreement dated as of March 1, 2013. (Designated in Form 8-K dated March 25, 2013, File No. 1-14174, as Exhibit 10.1.)
	(g)	14	—	Amended and Restated Loan Agreement dated as of March 1, 2013. (Designated in Form 8-K dated March 25, 2013, File No. 1-14174, as Exhibit 10.2.)
	(g)	15	—	Amended and Restated Loan Agreement dated as of March 1, 2013. (Designated in Form 8-K dated March 25, 2013, File No. 1-14174, as Exhibit 10.3.)
	(g)	16	—	Amended and Restated Loan Agreement dated as of March 1, 2013. (Designated in Form 8-K dated March 25, 2013, File No. 1-14174, as Exhibit 10.4.)

(14) Code of Ethics

Southern Company

*	(a)	—	The Southern Company Code of Ethics.

Alabama Power

	(b)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Georgia Power

	(c)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Gulf Power

(d) — The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Mississippi Power

(e) — The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Southern Power

(f) — The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Southern Company Gas

(g) — The Southern Company Code of Ethics. See Exhibit 14(a) herein.

(21) Subsidiaries of Registrants

Southern Company

* (a) — Subsidiaries of Registrant.

Alabama Power

(b) — Subsidiaries of Registrant. See Exhibit 21(a) herein.

Georgia Power

(c) — Subsidiaries of Registrant. See Exhibit 21(a) herein.

Gulf Power

(d) — Subsidiaries of Registrant. See Exhibit 21(a) herein.

Mississippi Power

(e) — Subsidiaries of Registrant. See Exhibit 21(a) herein.

Southern Power

Omitted pursuant to General Instruction I(2)(b) of Form 10-K.

Southern Company Gas

Omitted pursuant to General Instruction I(2)(b) of Form 10-K

(23) Consents of Experts and Counsel

Southern Company

* (a) 1 — Consent of Deloitte & Touche LLP.

Alabama Power

* (b) 1 — Consent of Deloitte & Touche LLP.

Georgia Power

* (c) 1 — Consent of Deloitte & Touche LLP.

Gulf Power

* (d) 1 — Consent of Deloitte & Touche LLP.

Southern Power

* (f) 1 — Consent of Deloitte & Touche LLP.

Southern Company Gas

* (g) 1 — Consent of Deloitte & Touche LLP.
* (g) 2 — Consent of PricewaterhouseCoopers LLP.
* (g) 3 — Consent of PricewaterhouseCoopers LLP.

(24) Powers of Attorney and Resolutions

Southern Company

* (a) — Power of Attorney and resolution.

Alabama Power

* (b) — Power of Attorney and resolution.

Georgia Power

* (c) — Power of Attorney and resolution.

Gulf Power

*	(d)		—	Power of Attorney and resolution.

Mississippi Power

*	(e)		—	Power of Attorney and resolution.

Southern Power

*	(f)		—	Power of Attorney and resolution.

Southern Company Gas

*	(g)		—	Power of Attorney and resolution.

(31) Section 302 Certifications

Southern Company

*	(a)	1	—	Certificate of Southern Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(a)	2	—	Certificate of Southern Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Alabama Power

*	(b)	1	—	Certificate of Alabama Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(b)	2	—	Certificate of Alabama Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Georgia Power

*	(c)	1	—	Certificate of Georgia Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(c)	2	—	Certificate of Georgia Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Gulf Power

*	(d)	1	—	Certificate of Gulf Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(d)	2	—	Certificate of Gulf Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

*	(e)	1	—	Certificate of Mississippi Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(e)	2	—	Certificate of Mississippi Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Southern Power

*	(f)	1	—	Certificate of Southern Power Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(f)	2	—	Certificate of Southern Power Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Southern Company Gas

*	(g)	1	—	Certificate of Southern Company Gas' Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(g)	2	—	Certificate of Southern Company Gas' Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(32) Section 906 Certifications

Southern Company

*	(a)		—	Certificate of Southern Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Alabama Power

*	(b)		—	Certificate of Alabama Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Georgia Power

*	(c)	—	Certificate of Georgia Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Gulf Power

*	(d)	—	Certificate of Gulf Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

*	(e)	—	Certificate of Mississippi Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Southern Power

*	(f)	—	Certificate of Southern Power Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Southern Company Gas

*	(g)	—	Certificate of Southern Company Gas' Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

(99) Additional Exhibits

Southern Company Gas

*	(g)	—	The financial statements of Southern Natural Gas Company, L.L.C., pursuant to Rule 3-09 of Regulation S-X.

(101) XBRL-Related Documents

*	INS	—	XBRL Instance Document
*	SCH	—	XBRL Taxonomy Extension Schema Document
*	CAL	—	XBRL Taxonomy Calculation Linkbase Document
*	DEF	—	XBRL Definition Linkbase Document
*	LAB	—	XBRL Taxonomy Label Linkbase Document
*	PRE	—	XBRL Taxonomy Presentation Linkbase Document

When recorded return to:

David Hight, Esq.
Ice Miller LLP
2300 Cabot Drive
Suite 455
Lisle, IL 60532

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SUPPLEMENTAL INDENTURE

MADE AS OF JUNE 16, 2016, TO BE EFFECTIVE JUNE 23, 2016

NORTHERN ILLINOIS GAS COMPANY

TO

THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A.

TRUSTEE UNDER INDENTURE DATED AS OF

JANUARY 1, 1954

and

SUPPLEMENTAL INDENTURES THERETO

FIRST MORTGAGE BONDS 2.66% SERIES DUE JUNE 20, 2026
FIRST MORTGAGE BONDS 2.91% SERIES DUE JUNE 20, 2031
FIRST MORTGAGE BONDS 3.27% SERIES DUE JUNE 20, 2036

Prepared by Mark A. Sternberg, Schiff Hardin LLP, 233 S. Wacker Drive, Chicago, IL 60606

THIS SUPPLEMENTAL INDENTURE, made as of June 16, 2016 and effective June 23, 2016, between NORTHERN ILLINOIS GAS COMPANY, a corporation organized and existing under the laws of the State of Illinois (hereinafter called the " **Company** "), and THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A. (hereinafter called the " **Trustee** "), as successor Trustee under an Indenture dated as of January 1, 1954, as supplemented by Supplemental Indentures dated (or made effective), respectively, February 9, 1954, April 1, 1956, June 1, 1959, July 1, 1960, June 1, 1963, July 1, 1963, August 1, 1964, August 1, 1965, May 1, 1966, August 1, 1966, July 1, 1967, June 1, 1968, December 1, 1969, August 1, 1970, June 1, 1971, July 1, 1972, July 1, 1973, April 1, 1975, April 30, 1976, April 30, 1976, July 1, 1976, August 1, 1976, December 1, 1977, January 15, 1979, December 1, 1981, March 1, 1983, October 1, 1984, December 1, 1986, March 15, 1988, July 1, 1988, July 1, 1989, July 15, 1990, August 15, 1991, July 15, 1992, February 1, 1993, March 15, 1993, May 1, 1993, July 1, 1993, August 15, 1994, October 15, 1995, May 10, 1996, August 1, 1996, June 1, 1997, October 15, 1997, February 15, 1998, June 1, 1998, February 1, 1999, February 1, 2001, May 15, 2001, August 15, 2001, December 15, 2001, December 1, 2003, December 15, 2006, August 15, 2008, July 30, 2009, February 1, 2011 and October 26, 2012, such Indenture dated as of January 1, 1954, as so supplemented, being hereinafter called the " **Indenture** ."

WITNESSETH:

WHEREAS, the Indenture provides for the issuance from time to time thereunder, in series, of bonds of the Company for the purposes and subject to the limitations therein specified; and

WHEREAS, the Company desires, by this Supplemental Indenture, to create three additional series of bonds to be issuable under the Indenture, such bonds to be designated, respectively, (a) "First Mortgage Bonds 2.66% Series due June 20, 2026" (hereinafter called the " **bonds of the 2026 Series** "), (b) "First Mortgage Bonds 2.91% Series due June 20, 2031" (hereinafter called the " **bonds of the 2031 Series** "), and (c) "First Mortgage Bonds 3.27% due June 20, 2036" (hereinafter called the " **bonds of the 2036 Series** "; the bonds of the 2026 Series, the bonds of the 2031 Series and bonds of the 2036 Series, hereinafter called, collectively the " **bonds of this Supplemental Indenture** "), and the terms and provisions to be contained in the bonds of this Supplemental Indenture or to be otherwise applicable thereto to be as set forth in this Supplemental Indenture; and

WHEREAS, the forms, respectively, of the bonds of this Supplemental Indenture, and the Trustee's certificate to be endorsed on all bonds of this Supplemental Indenture, are to be substantially as follows:

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(FORM OF FACE OF BOND OF 2026 SERIES)

NO. RU-2016-A-__ $________

Ill. Commerce Commission No. 6694 CUSIP No. 665228 C@9

NORTHERN ILLINOIS GAS COMPANY

First Mortgage Bond 2.66% Series due June 20, 2026

NORTHERN ILLINOIS GAS COMPANY, an Illinois corporation (hereinafter called the " **Company** "), for value received, hereby promises to pay to or registered assigns, the sum of Dollars, on June 20, 2026, and to pay to the registered owner hereof interest on said sum from the date hereof until said sum shall be paid, at the rate of 2.66% per annum, payable semi-annually on the twentieth day of June and the twentieth day of December in each year. Both the principal of and the interest on this bond shall be payable at the office or agency of the Company in the City of Chicago, State of Illinois, or, at the option of the registered owner, at the office or agency of the Company in the Borough of Manhattan, The City and State of New York, in any coin or currency of the United States of America which at the time of payment is legal tender for the payment of public and private debts. Any installment of interest on this bond may, at the Company's option, be paid by mailing checks for such interest payable to or upon the written order of the person entitled thereto to the address of such person as it appears on the registration books.

So long as there is no existing default in the payment of interest on this bond, the interest so payable on any interest payment date will be paid to the person in whose name this bond is registered on June 5 or December 5 (whether or not a business day), as the case may be, next preceding such interest payment date. If and to the extent that the Company shall default in the payment of interest due on such interest payment date, such defaulted interest shall be paid to the person in whose name this bond is registered on the record date fixed, in advance, by the Company for the payment of such defaulted interest.

Additional provisions of this bond are set forth on the reverse hereof.

This bond shall not be entitled to any security or benefit under the Indenture or be valid or become obligatory for any purpose unless and until it shall have been authenticated by the execution by the Trustee, or its successor in trust under the Indenture, of the certificate endorsed hereon.

IN WITNESS WHEREOF, Northern Illinois Gas Company has caused this bond to be executed in its name by its Executive Vice President, manually or by facsimile signature, and has caused its corporate seal to be impressed hereon or a facsimile thereof to be imprinted hereon and to be attested by its Secretary, manually or by facsimile signature.

Dated: June 23, 2016

NORTHERN ILLINOIS GAS COMPANY

By: ____________________________

Executive Vice President

ATTEST:

____

Secretary

(FORM OF TRUSTEE'S CERTIFICATE OF AUTHENTICATION)

This bond is one of the bonds of the 2026 Series designated therein, referred to and described in the within-mentioned Supplemental Indenture dated as of June 16, 2016, effective June 23, 2016.

THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A.,
TRUSTEE

By: ____________________________________
Authorized Officer

Dated: June 23, 2016

(FORM OF REVERSE SIDE OF BOND OF 2026 SERIES)

This bond is one, of the series hereinafter specified, of the bonds issued and to be issued in series from time to time under and in accordance with and secured by an Indenture dated as of January 1, 1954, to The Bank of New York Mellon Trust Company, N.A., as Trustee, as supplemented by certain indentures supplemental thereto, executed and delivered to the Trustee; and this bond is one of a series of such bonds, designated "Northern Illinois Gas Company First Mortgage Bond 2.66% Series due June 20, 2026" (herein called " **bonds of this Series** "), the issuance of which is provided for by a Supplemental Indenture dated as of June 16, 2016, effective June 23, 2016 (hereinafter called the " **Supplemental Indenture** "), executed and delivered by the Company to the Trustee. The term " **Indenture** ", as hereinafter used, means said Indenture dated as of January 1, 1954, and all indentures supplemental thereto (including, without limitation, the Supplemental Indenture) from time to time in effect. Reference is made to the Indenture for a description of the property mortgaged and pledged, the nature and extent of the security, the rights of the holders and registered owners of said bonds, of the Company and of the Trustee in respect of the security, and the terms and conditions governing the issuance and security of said bonds.

Any transferee, by its acceptance of a bond registered in its name (or the name of its nominee), shall be deemed to have made the representation set forth in Section 6.2 of the Bond Purchase Agreement dated as of June 16, 2016 among the Company and the purchasers listed on Schedule A attached thereto, as amended, restated, supplemented or otherwise modified from time to time.

With the consent of the Company and to the extent permitted by and as provided in the Indenture, modifications or alterations of the Indenture or of any supplemental indenture and of the rights and obligations of the Company and of the holders and registered owners of the bonds may be made, and compliance with any provision of the Indenture or of any supplemental indenture may be waived, by the affirmative vote of the holders and registered owners of not less than sixty-six and two-thirds per centum (66 2/3%) in principal amount of the bonds then outstanding under the Indenture, and by the affirmative vote of the holders and registered owners of not less than sixty-six and two-thirds per centum (66 2/3%) in principal amount of the bonds of any series then outstanding under the Indenture and affected by such modification or alteration, in case one or more but less than all of the series of bonds then outstanding under the Indenture are so affected, but in any case excluding bonds disqualified from voting by reason of the Company's interest therein as provided in the Indenture; subject, however, to the condition, among other conditions stated in the Indenture, that no such modification or alteration shall be made which, among other things, will permit the extension of the time or times of payment of the principal of or the interest or the premium, if any, on this bond, or the reduction in the principal amount hereof or in the rate of interest or the amount of any premium hereon, or any other modification in the terms of payment of such principal, interest or premium, which terms of payment are unconditional, or, otherwise than as permitted by the Indenture, the creation of any lien ranking prior to or on a parity with the lien of the Indenture with respect to any of the mortgaged property, all as more fully provided in the Indenture.

The bonds of this Series may be called for redemption by the Company, as a whole at any time or in part from time to time, at a redemption price equal to 100% of the principal amount of the bonds of this Series to be redeemed plus accrued and unpaid interest on the principal amount being redeemed to the date of redemption and the Make-Whole Amount (as defined in the Supplemental Indenture) applicable thereto.

Notice of each redemption shall be mailed to all registered owners not less than thirty nor more than forty-five days before the redemption date.

In case of certain completed defaults specified in the Indenture, the principal of this bond may be declared or may become due and payable in the manner and with the effect provided in the Indenture.

No recourse shall be had for the payment of the principal of or the interest or the premium, if any, on this bond, or for any claim based hereon, or otherwise in respect hereof or of the Indenture, to or against any incorporator, stockholder, officer or director, past, present or future, of the Company or of any predecessor or successor corporation, either directly or through the Company or such predecessor or successor corporation, under any constitution or statute or rule of law, or by the enforcement of any assessment or penalty, or otherwise, all such liability of incorporators, stockholders, directors and officers being waived and released by the registered owner hereof by the acceptance of this bond and being likewise waived and released by the terms of the Indenture, all as more fully provided therein.

This bond is transferable by the registered owner hereof, in person or by duly authorized attorney, at the office or agency of the Company in the City of Chicago, State of Illinois, or, at the option of registered owner, at the office or agency of the Company in the Borough of Manhattan, The City and State of New York, upon surrender and cancellation of this bond; and thereupon a new registered bond or bonds without coupons of the same aggregate principal amount and series will, upon the payment of any transfer tax or taxes payable, be issued to the transferee in exchange herefor. The Company shall not be required to exchange or transfer this bond if this bond or a portion hereof has been selected for redemption.

The security represented by this certificate has not been registered under the Securities Act of 1933, as amended (the " **Securities Act** "), or qualified under any state securities laws and may not be transferred, sold or otherwise disposed of except while a registration statement is in effect or pursuant to an available exemption from registration under the Securities Act and applicable state securities laws.

(END OF FORM OF BOND OF 2026 SERIES)

(FORM OF FACE OF BOND OF 2031 SERIES)

NO. RU-2016-B-__ $________

Ill. Commerce Commission No. 6694 CUSIP No. 665228 C#7

NORTHERN ILLINOIS GAS COMPANY

First Mortgage Bond 2.91% Series due June 20, 2031

NORTHERN ILLINOIS GAS COMPANY, an Illinois corporation (hereinafter called the " **Company** "), for value received, hereby promises to pay to or registered assigns, the sum of Dollars, on June 20, 2031, and to pay to the registered owner hereof interest on said sum from the date hereof until said sum shall be paid, at the rate of 2.91% per annum, payable semi-annually on the twentieth day of June and the twentieth day of December in each year. Both the principal of and the interest on this bond shall be payable at the office or agency of the Company in the City of Chicago, State of Illinois, or, at the option of the registered owner, at the office or agency of the Company in the Borough of Manhattan, The City and State of New York, in any coin or currency of the United States of America which at the time of payment is legal tender for the payment of public and private debts. Any installment of interest on this bond may, at the Company's option, be paid by mailing checks for such interest payable to or upon the written order of the person entitled thereto to the address of such person as it appears on the registration books.

So long as there is no existing default in the payment of interest on this bond, the interest so payable on any interest payment date will be paid to the person in whose name this bond is registered on June 5 or December 5 (whether or not a business day), as the case may be, next preceding such interest payment date. If and to the extent that the Company shall default in the payment of interest due on such interest payment date, such defaulted interest shall be paid to the person in whose name this bond is registered on the record date fixed, in advance, by the Company for the payment of such defaulted interest.

Additional provisions of this bond are set forth on the reverse hereof.

This bond shall not be entitled to any security or benefit under the Indenture or be valid or become obligatory for any purpose unless and until it shall have been authenticated by the execution by the Trustee, or its successor in trust under the Indenture, of the certificate endorsed hereon.

IN WITNESS WHEREOF, Northern Illinois Gas Company has caused this bond to be executed in its name by its Executive Vice President, manually or by facsimile signature, and has caused its corporate seal to be impressed hereon or a facsimile thereof to be imprinted hereon and to be attested by its Secretary, manually or by facsimile signature.

Dated: June 23, 2016

NORTHERN ILLINOIS GAS COMPANY

By: ______________________
Executive Vice President

ATTEST:

____
Secretary

(FORM OF TRUSTEE'S CERTIFICATE OF AUTHENTICATION)

This bond is one of the bonds of the 2031 Series designated therein, referred to and described in the within-mentioned Supplemental Indenture dated as of June 16, 2016, effective June 23, 2016.

THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A.,
TRUSTEE

By: ___________________________________
Authorized Officer

Dated: June 23, 2016

(FORM OF REVERSE SIDE OF BOND OF 2031 SERIES)

This bond is one, of the series hereinafter specified, of the bonds issued and to be issued in series from time to time under and in accordance with and secured by an Indenture dated as of January 1, 1954, to The Bank of New York Mellon Trust Company, N.A., as Trustee, as supplemented by certain indentures supplemental thereto, executed and delivered to the Trustee; and this bond is one of a series of such bonds, designated “Northern Illinois Gas Company First Mortgage Bond 2.91% Series due June 20, 2031” (herein called “ **bonds of this Series** ”), the issuance of which is provided for by a Supplemental Indenture dated as of June 16, 2016, effective June 23, 2016 (hereinafter called the “ **Supplemental Indenture** ”), executed and delivered by the Company to the Trustee. The term “ **Indenture** ”, as hereinafter used, means said Indenture dated as of January 1, 1954, and all indentures supplemental thereto (including, without limitation, the Supplemental Indenture) from time to time in effect. Reference is made to the Indenture for a description of the property mortgaged and pledged, the nature and extent of the security, the rights of the holders and registered owners of said bonds, of the Company and of the Trustee in respect of the security, and the terms and conditions governing the issuance and security of said bonds.

Any transferee, by its acceptance of a bond registered in its name (or the name of its nominee), shall be deemed to have made the representation set forth in Section 6.2 of the Bond Purchase Agreement dated as of June 16, 2016 among the Company and the purchasers listed on Schedule A attached thereto, as amended, restated, supplemented or otherwise modified from time to time.

With the consent of the Company and to the extent permitted by and as provided in the Indenture, modifications or alterations of the Indenture or of any supplemental indenture and of the rights and obligations of the Company and of the holders and registered owners of the bonds may be made, and compliance with any provision of the Indenture or of any supplemental indenture may be waived, by the affirmative vote of the holders and registered owners of not less than sixty-six and two-thirds per centum (66 2/3%) in principal amount of the bonds then outstanding under the Indenture, and by the affirmative vote of the holders and registered owners of not less than sixty-six and two-thirds per centum (66 2/3%) in principal amount of the bonds of any series then outstanding under the Indenture and affected by such modification or alteration, in case one or more but less than all of the series of bonds then outstanding under the Indenture are so affected, but in any case excluding bonds disqualified from voting by reason of the Company’s interest therein as provided in the Indenture; subject, however, to the condition, among other conditions stated in the Indenture, that no such modification or alteration shall be made which, among other things, will permit the extension of the time or times of payment of the principal of or the interest or the premium, if any, on this bond, or the reduction in the principal amount hereof or in the rate of interest or the amount of any premium hereon, or any other modification in the terms of payment of such principal, interest or premium, which terms of payment are unconditional, or, otherwise than as permitted by the Indenture, the creation of any lien ranking prior to or on a parity with the lien of the Indenture with respect to any of the mortgaged property, all as more fully provided in the Indenture.

The bonds of this Series may be called for redemption by the Company, as a whole at any time or in part from time to time, at a redemption price equal to 100% of the principal amount of the bonds of this Series to be redeemed plus accrued and unpaid interest on the principal amount being redeemed to the date of redemption and the Make-Whole Amount (as defined in the Supplemental Indenture) applicable thereto.

Notice of each redemption shall be mailed to all registered owners not less than thirty nor more than forty-five days before the redemption date.

In case of certain completed defaults specified in the Indenture, the principal of this bond may be declared or may become due and payable in the manner and with the effect provided in the Indenture.

No recourse shall be had for the payment of the principal of or the interest or the premium, if any, on this bond, or for any claim based hereon, or otherwise in respect hereof or of the Indenture, to or against any incorporator, stockholder, officer or director, past, present or future, of the Company or of any predecessor or successor corporation, either directly or through the Company or such predecessor or successor corporation, under any constitution or statute or rule of law, or by the enforcement of any assessment or penalty, or otherwise, all such liability of incorporators, stockholders, directors and officers being waived and released by the registered owner hereof by the acceptance of this bond and being likewise waived and released by the terms of the Indenture, all as more fully provided therein.

This bond is transferable by the registered owner hereof, in person or by duly authorized attorney, at the office or agency of the Company in the City of Chicago, State of Illinois, or, at the option of registered owner, at the office or agency of the Company in the Borough of Manhattan, The City and State of New York, upon surrender and cancellation of this bond; and thereupon a new registered bond or bonds without coupons of the same aggregate principal amount and series will, upon the payment of any transfer tax or taxes payable, be issued to the transferee in exchange herefor. The Company shall not be required to exchange or transfer this bond if this bond or a portion hereof has been selected for redemption.

The security represented by this certificate has not been registered under the Securities Act of 1933, as amended (the " **Securities Act** "), or qualified under any state securities laws and may not be transferred, sold or otherwise disposed of except while a registration statement is in effect or pursuant to an available exemption from registration under the Securities Act and applicable state securities laws.

(END OF FORM OF BOND OF 2031 SERIES)

(FORM OF FACE OF BOND OF 2036 SERIES)

NO. RU-2016-C-__ $________

Ill. Commerce Commission No. 6694 CUSIP No. 665228 D*0

NORTHERN ILLINOIS GAS COMPANY

First Mortgage Bond 3.27% Series due June 20, 2036

NORTHERN ILLINOIS GAS COMPANY, an Illinois corporation (hereinafter called the " **Company** "), for value received, hereby promises to pay to or registered assigns, the sum of Dollars, on June 20, 2036, and to pay to the registered owner hereof interest on said sum from the date hereof until said sum shall be paid, at the rate of 3.27% per annum, payable semi-annually on the twentieth day of June and the twentieth day of December in each year. Both the principal of and the interest on this bond shall be payable at the office or agency of the Company in the City of Chicago, State of Illinois, or, at the option of the registered owner, at the office or agency of the Company in the Borough of Manhattan, The City and State of New York, in any coin or currency of the United States of America which at the time of payment is legal tender for the payment of public and private debts. Any installment of interest on this bond may, at the Company's option, be paid by mailing checks for such interest payable to or upon the written order of the person entitled thereto to the address of such person as it appears on the registration books.

So long as there is no existing default in the payment of interest on this bond, the interest so payable on any interest payment date will be paid to the person in whose name this bond is registered on June 5 or December 5 (whether or not a business day), as the case may be, next preceding such interest payment date. If and to the extent that the Company shall default in the payment of interest due on such interest payment date, such defaulted interest shall be paid to the person in whose name this bond is registered on the record date fixed, in advance, by the Company for the payment of such defaulted interest.

Additional provisions of this bond are set forth on the reverse hereof.

This bond shall not be entitled to any security or benefit under the Indenture or be valid or become obligatory for any purpose unless and until it shall have been authenticated by the execution by the Trustee, or its successor in trust under the Indenture, of the certificate endorsed hereon.

IN WITNESS WHEREOF, Northern Illinois Gas Company has caused this bond to be executed in its name by its Executive Vice President, manually or by facsimile signature, and has caused its corporate seal to be impressed hereon or a facsimile thereof to be imprinted hereon and to be attested by its Secretary, manually or by facsimile signature.

Dated: June 23, 2016

NORTHERN ILLINOIS GAS COMPANY

By: ______________________

Executive Vice President

ATTEST:

____

Secretary

(FORM OF TRUSTEE'S CERTIFICATE OF AUTHENTICATION)

This bond is one of the bonds of the 2036 Series designated therein, referred to and described in the within-mentioned Supplemental Indenture dated as of June 16, 2016, effective June 23, 2016.

THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A., TRUSTEE

By: ____

Authorized Officer

Dated: June 23, 2016

(FORM OF REVERSE SIDE OF BOND OF 2036 SERIES)

This bond is one, of the series hereinafter specified, of the bonds issued and to be issued in series from time to time under and in accordance with and secured by an Indenture dated as of January 1, 1954, to The Bank of New York Mellon Trust Company, N.A., as Trustee, as supplemented by certain indentures supplemental thereto, executed and delivered to the Trustee; and this bond is one of a series of such bonds, designated "Northern Illinois Gas Company First Mortgage Bond 3.27% Series due June 20, 2036" (herein called " **bonds of this Series** "), the issuance of which is provided for by a Supplemental Indenture dated as of June 16, 2016, effective June 23, 2016 (hereinafter called the " **Supplemental Indenture** "), executed and delivered by the Company to the Trustee. The term " **Indenture** ", as hereinafter used, means said Indenture dated as of January 1, 1954, and all indentures supplemental thereto (including, without limitation, the Supplemental Indenture) from time to time in effect. Reference is made to the Indenture for a description of the property mortgaged and pledged, the nature and extent of the security, the rights of the holders and registered owners of said bonds, of the Company and of the Trustee in respect of the security, and the terms and conditions governing the issuance and security of said bonds.

Any transferee, by its acceptance of a bond registered in its name (or the name of its nominee), shall be deemed to have made the representation set forth in Section 6.2 of the Bond Purchase Agreement dated as of June 16, 2016 among the Company and the purchasers listed on Schedule A attached thereto, as amended, restated, supplemented or otherwise modified from time to time.

With the consent of the Company and to the extent permitted by and as provided in the Indenture, modifications or alterations of the Indenture or of any supplemental indenture and of the rights and obligations of the Company and of the holders and registered owners of the bonds may be made, and compliance with any provision of the Indenture or of any supplemental indenture may be waived, by the affirmative vote of the holders and registered owners of not less than sixty-six and two-thirds per centum (66 2/3%) in principal amount of the bonds then outstanding under the Indenture, and by the affirmative vote of the holders and registered owners of not less than sixty-six and two-thirds per centum (66 2/3%) in principal amount of the bonds of any series then outstanding under the Indenture and affected by such modification or alteration, in case one or more but less than all of the series of bonds then outstanding under the Indenture are so affected, but in any case excluding bonds disqualified from voting by reason of the Company's interest therein as provided in the Indenture; subject, however, to the condition, among other conditions stated in the Indenture, that no such modification or alteration shall be made which, among other things, will permit the extension of the time or times of payment of the principal of or the interest or the premium, if any, on this bond, or the reduction in the principal amount hereof or in the rate of interest or the amount of any premium hereon, or any other modification in the terms of payment of such principal, interest or premium, which terms of payment are unconditional, or, otherwise than as permitted by the Indenture, the creation of any lien ranking prior to or on a parity with the lien of the Indenture with respect to any of the mortgaged property, all as more fully provided in the Indenture.

The bonds of this Series may be called for redemption by the Company, as a whole at any time or in part from time to time, at a redemption price equal to 100% of the principal amount of the bonds of this Series to be redeemed plus accrued and unpaid interest on the principal amount being redeemed to the date of redemption and the Make-Whole Amount (as defined in the Supplemental Indenture) applicable thereto.

Notice of each redemption shall be mailed to all registered owners not less than thirty nor more than forty-five days before the redemption date.

In case of certain completed defaults specified in the Indenture, the principal of this bond may be declared or may become due and payable in the manner and with the effect provided in the Indenture.

No recourse shall be had for the payment of the principal of or the interest or the premium, if any, on this bond, or for any claim based hereon, or otherwise in respect hereof or of the Indenture, to or against any incorporator, stockholder, officer or director, past, present or future, of the Company or of any predecessor or successor corporation, either directly or through the Company or such predecessor or successor corporation, under any constitution or statute or rule of law, or by the enforcement of any assessment or penalty, or otherwise, all such liability of incorporators, stockholders, directors and officers being waived and released by the registered owner hereof by the acceptance of this bond and being likewise waived and released by the terms of the Indenture, all as more fully provided therein.

This bond is transferable by the registered owner hereof, in person or by duly authorized attorney, at the office or agency of the Company in the City of Chicago, State of Illinois, or, at the option of registered owner, at the office or agency of the Company in the Borough of Manhattan, The City and State of New York, upon surrender and cancellation of this bond; and thereupon a new registered bond or bonds without coupons of the same aggregate principal amount and series will, upon the payment of any transfer tax or taxes payable, be issued to the transferee in exchange herefor. The Company shall not be required to exchange or transfer this bond if this bond or a portion hereof has been selected for redemption.

The security represented by this certificate has not been registered under the Securities Act of 1933, as amended (the " **Securities Act** "), or qualified under any state securities laws and may not be transferred, sold or otherwise disposed of except while a registration statement is in effect or pursuant to an available exemption from registration under the Securities Act and applicable state securities laws.

(END OF FORM OF BOND OF 2036 SERIES)

and

WHEREAS, all acts and things necessary to make this Supplemental Indenture, when duly executed and delivered, a valid, binding and legal instrument in accordance with its terms, and for the purposes herein expressed, have been done and performed, and the execution and delivery of this Supplemental Indenture have in all respects been duly authorized;

NOW THEREFORE, in consideration of the premises and of the sum of one dollar paid by the Trustee to the Company, and for other good and valuable consideration, the receipt of which is hereby acknowledged, for the purpose of securing the due and punctual payment of the principal of and the interest and premium, if any, on all bonds which shall be issued under the Indenture, and for the purpose of securing the faithful performance and observance of all the covenants and conditions set forth in the Indenture and in all indentures supplemental thereto, the Company by these presents does grant, bargain, sell, transfer, assign, pledge, mortgage, warrant and convey unto The Bank of New York Mellon Trust Company, N.A., as Trustee, and its successor or successors in the trust hereby created, all property, real and personal (other than property expressly excepted from the lien and operation of the Indenture), which, at the actual date of execution and delivery of this Supplemental Indenture, is solely used or held for use in the operation by the Company of its gas utility system and in the conduct of its gas utility business and all property, real and personal, used or useful in the gas utility business (other than property expressly excepted from the lien and operation of the Indenture) acquired by the Company after the actual date of execution and delivery of this Supplemental Indenture or (subject to the provisions of Section 16.03 of the Indenture) by any successor corporation after such execution and delivery, and it is further agreed by and between the Company and the Trustee as follows:

ARTICLE I

BONDS OF THIS SUPPLEMENTAL INDENTURE

Section 1. The bonds of this Supplemental Indenture shall, as hereinbefore recited, be designated as the Company's (a) "First Mortgage Bonds 2.66% Series due June 20, 2026", (b) "First Mortgage Bonds 2.91% Series due June 20, 2031" and (c) "First Mortgage Bonds 3.27% Series due June 20, 2036", as applicable. The bonds of the 2026 Series which may be issued and outstanding shall not exceed $100,000,000 in aggregate principal amount, exclusive of bonds of such series authenticated and delivered pursuant to Section 4.12 of the Indenture. The bonds of the 2031 Series which may be issued and outstanding shall not exceed $100,000,000 in aggregate principal amount, exclusive of bonds of such series authenticated and delivered pursuant to Section 4.12 of the Indenture. The bonds of the 2036 Series which may be issued and outstanding shall not exceed $50,000,000 in aggregate principal amount, exclusive of bonds of such series authenticated and delivered pursuant to Section 4.12 of the Indenture.

Section 2. The bonds of this Supplemental Indenture shall be registered bonds without coupons, and the form of each series of such bonds, and of the Trustee's certificate of authentication to be endorsed on all bonds of this Supplemental Indenture, shall be substantially as hereinbefore recited, respectively.

Section 3. The bonds of this Supplemental Indenture shall be issued in the denomination of $500,000 each and in such integral multiple or multiples thereof as shall be determined and authorized by the Board of Directors of the Company or by any officer of the Company authorized by the Board of Directors to make such determination, the authorization of the denomination of any bond to be conclusively evidenced by the execution thereof on behalf of the Company. The bonds of the 2026 Series shall be numbered RU-2016-A-1 and consecutively upwards, or in such other appropriate manner as shall be determined and authorized by the Board

of Directors of the Company. The bonds of the 2031 Series shall be numbered RU-2016-B-1 and consecutively upwards, or in such other appropriate manner as shall be determined and authorized by the Board of Directors of the Company. The bonds of the 2036 Series shall be numbered RU-2016-C-1 and consecutively upwards, or in such other appropriate manner as shall be determined and authorized by the Board of Directors of the Company.

All bonds of this Supplemental Indenture shall be dated June 23, 2016 except that each bond issued on or after the first payment of interest thereon shall be dated as of the date of the interest payment date thereof to which interest shall have been paid on the bonds of its series next preceding the date of issue, unless issued on an interest payment date to which interest shall have been so paid, in which event such bonds shall be dated as of the date of issue; *provided* , *however* , that bonds issued on or after June 5 and before the next succeeding June 20 or on or after December 5 and before the next succeeding December 20 shall be dated the next succeeding interest payment date if interest shall have been paid to such date. The bonds of the 2026 Series shall mature on June 20, 2026 and shall bear interest at the rate of 2.66% per annum until the principal thereof shall be paid. The bonds of the 2031 Series shall mature on June 20, 2031 and shall bear interest at the rate of 2.91% per annum until the principal thereof shall be paid. The bonds of the 2036 Series shall mature on June 20, 2036 and shall bear interest at the rate of 3.27% per annum until the principal thereof shall be paid. Interest on the bonds of this Supplemental Indenture shall be calculated on the basis of a 360-day year consisting of twelve 30-day months and shall be payable semi-annually on the twentieth day of June and the twentieth day of December in each year, beginning December 20, 2016. So long as there is no existing default in the payment of interest on the bonds of this Supplemental Indenture, such interest shall be payable to the person in whose name each such bond is registered on the June 5 or December 5 (whether or not a business day), as the case may be, next preceding the respective interest payment dates; *provided* , *however* , if and to the extent that the Company shall default in the payment of interest due on such interest payment date, such defaulted interest shall be paid to the person in whose name each such bond is registered on the record date fixed, in advance, by the Company for the payment of such defaulted interest. Interest will accrue on overdue interest installments at the rate of (i) 2.66% per annum, with respect to the bonds of the 2026 Series, (ii) 2.91% per annum, with respect to the bonds of the 2031 Series, and (iii) 3.27% per annum, with respect to the bonds of the 2036 Series.

The principal of and interest and premium, if any, on the bonds of this Supplemental Indenture shall be payable in any coin or currency of the United States of America which at the time of payment is legal tender for the payment of public and private debts, and shall be payable at the office or agency of the Company in the City of Chicago, State of Illinois, or, at the option of the registered owner, at the office or agency of the Company in the Borough of Manhattan, The City and State of New York. Any installment of interest on the bonds may, at the Company’s option, be paid by mailing checks for such interest payable to or upon the written order of the person entitled thereto to the address of such person as it appears on the registration books. The bonds of this Supplemental Indenture shall be registrable, transferable and exchangeable in the manner provided in Sections 4.08 and 4.09 of the Indenture, at either of such offices or agencies.

Section 4. The bonds of this Supplemental Indenture, upon the mailing of notice and in the manner provided in Section 7.01 of the Indenture (except that no published notice shall be

required for the bonds of this Supplemental Indenture) and with the effect provided in Section 7.02 thereof, shall be redeemable at the option of the Company, as a whole at any time or in part from time to time, at a redemption price equal to 100% of the principal amount of the bonds of this Supplemental Indenture to be redeemed plus accrued and unpaid interest of the principal amount being redeemed to the date of redemption plus the Make-Whole Amount applicable thereto. **"Make-Whole Amount"** means, with respect to any bond of this Supplemental Indenture, an amount equal to the excess, if any, of the Discounted Value of the Remaining Scheduled Payments with respect to the Called Principal of such bond of this Supplemental Indenture over the amount of such Called Principal, *provided* that the Make-Whole Amount may in no event be less than zero. For the purposes of determining the Make-Whole Amount, the following terms have the following meanings:

"Called Principal" means, with respect to any bond of this Supplemental Indenture, the principal of such bond of this Supplemental Indenture that is to be redeemed.

"Discounted Value" means, with respect to the Called Principal of any bond of this Supplemental Indenture, the amount obtained by discounting all Remaining Scheduled Payments with respect to such Called Principal from their respective scheduled due dates to the Settlement Date with respect to such Called Principal, in accordance with accepted financial practice and at a discount factor (applied on the same periodic basis as that on which interest on the bond of this Supplemental Indenture is payable) equal to the Reinvestment Yield with respect to such Called Principal.

"Reinvestment Yield" means, with respect to the Called Principal of any bond of this Supplemental Indenture, the sum of (x) 0.50% plus (y) the yield to maturity implied by the "Ask Yield(s)" reported as of 10:00 a.m. (New York City time) on the second Business Day preceding the Settlement Date with respect to such Called Principal, on the display designated as "Page PX1" (or such other display as may replace Page PX1) on Bloomberg Financial Markets for the most recently issued actively traded on-the-run U.S. Treasury securities (" **Reported** ") having a maturity equal to the Remaining Average Life of such Called Principal as of such Settlement Date. If there are no such U.S. Treasury securities Reported having a maturity equal to such Remaining Average Life, then such implied yield to maturity will be determined by (a) converting U.S. Treasury bill quotations to bond equivalent yields in accordance with accepted financial practice and (b) interpolating linearly between the "Ask Yields" Reported for the applicable most recently issued actively traded on-the-run U.S. Treasury securities with the maturities (1) closest to and greater than such Remaining Average Life and (2) closest to and less than such Remaining Average Life. The Reinvestment Yield shall be rounded to the number of decimal places as appears in the interest rate of the applicable bond.

If such yields are not Reported or the yields Reported as of such time are not ascertainable (including by way of interpolation), then "Reinvestment Yield" means, with respect to the Called Principal of any bond of this Supplemental Indenture, the sum of (x) 0.50% plus (y) the yield to maturity implied by the U.S. Treasury constant maturity yields reported, for the latest day for which such yields have been so reported as of the second Business Day preceding the Settlement Date with respect to such Called

Principal, in Federal Reserve Statistical Release H.15 (or any comparable successor publication) for the U.S. Treasury constant maturity having a term equal to the Remaining Average Life of such Called Principal as of such Settlement Date. If there is no such U.S. Treasury constant maturity having a term equal to such Remaining Average Life, such implied yield to maturity will be determined by interpolating linearly between (1) the U.S. Treasury constant maturity so reported with the term closest to and greater than such Remaining Average Life and (2) the U.S. Treasury constant maturity so reported with the term closest to and less than such Remaining Average Life. The Reinvestment Yield shall be rounded to the number of decimal places as appears in the interest rate of the applicable bond.

"Remaining Average Life" means, with respect to any Called Principal, the number of years obtained by dividing (a) such Called Principal into (b) the sum of the products obtained by multiplying (1) the principal component of each Remaining Scheduled Payment with respect to such Called Principal by (2) the number of years, computed on the basis of a 360-day year comprised of twelve 30-day months and calculated to the nearest two decimal places, that will elapse between the Settlement Date with respect to such Called Principal and the scheduled due date of such Remaining Scheduled Payment.

"Remaining Scheduled Payments" means, with respect to the Called Principal of any bond of this Supplemental Indenture, all payments of such Called Principal and interest thereon that would be due after the Settlement Date with respect to such Called Principal if no payment of such Called Principal were made prior to its scheduled due date, *provided* that if such Settlement Date is not a date on which interest payments are due to be made under the terms of the bond of this Supplemental Indenture, then the amount of the next succeeding scheduled interest payment will be reduced by the amount of interest accrued to such Settlement Date and required to be paid on such Settlement Date pursuant to the terms of this Supplemental Indenture.

"Settlement Date" means, with respect to the Called Principal of any bond of this Supplemental Indenture, the date on which such Called Principal is to be redeemed.

Section 5. No sinking fund is to be provided for the bonds of this Supplemental Indenture.

ARTICLE II

MISCELLANEOUS PROVISIONS

Section 6. This Supplemental Indenture is executed by the Company and the Trustee pursuant to provisions of Section 4.02 of the Indenture and the terms and conditions hereof shall be deemed to be a part of the terms and conditions of the Indenture for any and all purposes. The Indenture, as heretofore supplemented and as supplemented by this Supplemental Indenture, is in all respects ratified and confirmed.

Section 7. This Supplemental Indenture shall bind and, subject to the provisions of Article XVI of the Indenture, inure to the benefit of the respective successors and assigns of the parties hereto.

Section 8. Although this Supplemental Indenture is made as of June 16, 2016, effective June 23, 2016, it shall be effective only from and after the actual time of its execution and delivery by the Company and the Trustee on the date indicated by their respective acknowledgements hereto.

Section 9. This Supplemental Indenture may be simultaneously executed in any number of counterparts, and all such counterparts executed and delivered, each as an original, shall constitute but one and the same instrument.

Section 10. The recitals herein are deemed to be those of the Company and not of the Trustee. The Trustee makes no representations as to the validity or sufficiency of this Supplemental Indenture.

IN WITNESS WHEREOF, Northern Illinois Gas Company has caused this Supplemental Indenture to be executed in its name by its Executive Vice President and its corporate seal to be hereunto affixed and attested by its Secretary, and The Bank of New York Mellon Trust Company, N.A., as Trustee under the Indenture, has caused this Supplemental Indenture to be executed in its name by one of its Vice Presidents, and its seal to be hereunto affixed and attested by one of its Vice Presidents, all as of the day and year first above written.

NORTHERN ILLINOIS GAS COMPANY

By: /s/ Paul R. Shlanta
Name: Paul R. Shlanta
Title: EVP and General Counsel

ATTEST:

By: /s/ Myra C. Bierria
Name: Myra C. Bierria
Title: Secretary

[Signature Page to 2016 Supplemental Indenture]

THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A.,
as Trustee

By: /s/ Manjari Purkayastha
Name: Manjari Purkayastha
Title: Vice President

(Seal)

ATTEST:

By: /s/ Valere Boyd
Name: Valere Boyd
Title: Vice President

[Signature Page to 2016 Supplemental Indenture]

STATE OF GEORGIA } SS:
COUNTY OF GWINNETT }

I, Dione Edwards, a Notary Public in the State aforesaid, DO HEREBY CERTIFY that Paul R. Shlanta, Executive Vice President and General Counsel of Northern Illinois Gas Company, an Illinois corporation, one of the parties described in and which executed the foregoing instrument, and Myra C. Bierria, Secretary of said corporation, who are both personally known to me to be the same persons whose names are subscribed to the foregoing instrument as such Executive Vice President and General Counsel and Secretary, respectively, and who are both personally known to me to be the Executive Vice President and General Counsel and Secretary, respectively, of said corporation, appeared before me this day in person and severally acknowledged that they signed, sealed, executed and delivered said instrument as their free and voluntary act as such Executive Vice President and General Counsel and Secretary, respectively, of said corporation, and as the free and voluntary act of said corporation, for the uses and purposes therein set forth.

GIVEN under my hand and notarial seal this 16th day of June, 2016.

/s/ Dione Edwards

Notary Public

My Commission expires October 13, 2019.

ACKNOWLEDGMENT

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

State of California

County of Los Angeles

On June 16, 2016 before me, Alex Dominguez, Notary Public personally appeared Manjari Purkayastha and Valere Boyd,

who proved to me on the basis of satisfactory evidence to be the person(s) whose name(s) are subscribed to the within instrument and acknowledged to me that they executed the same in their authorized capacity(ies), and that by their signature(s) on the instrument the person(s), or the entity upon behalf of which the person(s) acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

Signature /s/ Alex Dominguez **(Seal)**

RECORDING DATA [1]

This Supplemental Indenture was recorded on the following dates in the office of the Recorder of Deeds in certain counties in the State of Illinois, as follows:

County	Document No. [2]	Date Recorded
Cook		
Adams		
Boone		
Bureau		
Carroll		
Champaign		
DeKalb		
DeWitt		
DuPage		
Ford		
Grundy		
Hancock		
Henderson		
Henry		
Iroquois		
JoDaviess		
Kane		
Kankakee		
Kendall		
Lake		
LaSalle		
Lee		
Livingston		
McHenry		
McLean		
Mercer		
Ogle		
Piatt		
Pike		
Rock Island		
Stephenson		
Tazewell		
Vermilion		
Whiteside		
Will		

[1] This page to be intentionally omitted from versions submitted for recording.

[2] For delivery at Closing, Nicor to include all document numbers received prior to Closing. With respect to recordings for which no document number shall have been received prior to Closing, Nicor to provide such numbers post-Closing.

County	Document No. [2]	Date Recorded
Winnebago		
Woodford		

Exhibit 10(a)17

DEFERRED COMPENSATION AGREEMENT

THIS DEFERRED COMPENSATION AGREEMENT ("Agreement") is made and entered into by THE SOUTHERN COMPANY, ("Southern"), SOUTHERN COMPANY SERVICES, INC. ("SCS"), ALABAMA POWER COMPANY (the "Company") (collectively the "Southern Parties") and MARK A. CROSSWHITE ("Employee"), this 30th day of July, 2008 ("Effective Date").

W I T N E S S E T H

WHEREAS, Employee is a highly compensated employee of the Company and is a member of its management;

WHEREAS, although Employee's career with the Southern Company system began on March 15, 2004, his valuable services to Southern and its affiliated subsidiaries began at an earlier date while he was employed as a lawyer with Balch & Bingham LLP;

WHEREAS, Employee has accepted the transfer of his employment within Southern's group of affiliated companies on several occasions, having been an officer and employee of SCS and the Company;

WHEREAS, the Southern Parties desire to set forth the manner in which the benefits provided to Employee under this Agreement as a result of the recognition of his prior valuable service will be shared; and

WHEREAS, the parties desire to restate all earlier agreements, including that certain Deferred Compensation Agreement entered into April 12, 2004, and to provide for the assignment of this Agreement to any successor employer in the Southern affiliated group in the event Employee hereafter transfers his employment to any such successor employer.

NOW, THEREFORE, in consideration of the premises, and the agreements of the parties set forth herein, and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto, intending to be legally bound, hereby covenant and agree as follows:

1. Eligibility for Supplemental Retirement Benefits .

(a) Subject to the terms of this Agreement, if the Employee remains employed with the Company until such time he has accrued five (5) years of vesting service (the "Service Requirement") under The Southern Company Pension Plan (the "Pension Plan"), the Southern Parties shall pay to Employee (or if Payment continues, to Employee's designated beneficiary, as

the case may be, in the event of Employee's death as described in Section 1(c) hereof) the supplemental retirement payment (the "Payment") described in Section 1(b) hereof (to be shared among the Company, Southern and SCS in such pro rata portions as set forth in Sections 2 or 3 hereof).

The Service Requirement shall not apply if the Employee is terminated under circumstances that result in eligibility for severance benefits under The Southern Company Executive Change in Control Severance Plan ("Change in Control Termination"). With respect to a Change in Control Termination only, the Employee shall be deemed to have accrued under this Agreement a vested deferred pension benefit (and not a retirement benefit) based on his actual age and service plus the service provided under Section 1(b)(i) below otherwise determined as more generally described in Section 1(b) below. For the avoidance of doubt, if the Service Requirement is satisfied before a Change in Control Termination, the Employee's Payment under this Agreement shall be based on Employee's actual age and service plus the service provided under Section 1(b)(i) below as otherwise determined as more generally described in Section 1(b) below.

(b) In the event Employee satisfies the requirements of this Agreement, the Payment shall be an amount equal to the difference between:

(i) the amounts payable to Employee under the Pension Plan, the Southern Company Supplemental Benefit Plan ("SBP") and the Southern Company Supplemental Executive Retirement Plan ("SERP") (collectively, the "Retirement Plans") as each shall then be in effect, determined as if Employee had an additional fifteen (15) years of Accredited Service under the Pension Plan; and

(ii) the amounts Employee is actually entitled to receive under the Retirement Plans at Employee's retirement, as each shall then be in effect, as further determined and payable in accordance with Section 1(d) hereof.

(c) Payment in the Event of Death. In the event Employee dies and Payment continues to Employee's designated beneficiary (the "Death Benefit"), such Payment shall be made in accordance with Section 1(d) hereof.

(d) Calculation, Form and Timing of Payment. The calculation (including actuarial assumptions), form and timing of the Payment or Death Benefit upon the occurrence of a "separation from service" as defined in Section 409A of the Code and the regulations promulgated thereunder ("Separation from Service") shall be the same as the calculation (including actuarial assumptions), form and timing of similar payments to Employee or designated beneficiary as the case may be, under the terms of the SERP and the SBP (but, as to the SBP, only concerning the "Pension Benefit" provided thereunder) as each may be amended from time to time.

(e) Termination for Cause. In the event of Employee's termination of employment for Cause at any time, the Employee shall forfeit the entire benefit provided in this Section 1, and Southern, the Company, SCS and any of their respective affiliates (the "Southern Entities") shall have no further obligations with respect to any amount under this Agreement. As used in this Agreement, the term "Cause" shall mean gross negligence or willful misconduct in the performance of the duties and services required in the course of employment by the Company; the final conviction of a felony or misdemeanor involving moral turpitude; the carrying out of any activity or the making of any statement which would prejudice the good name and standing of any of the Southern Entities or would bring any of the Southern Entities into contempt, ridicule or would reasonably shock or offend any community in which any of the Southern Entities is located; a material breach of the fiduciary obligations owed by an officer and an employee to any of the Southern Entities; or the Employee's unsatisfactory performance of the duties and services required by his employment.

(f) Misconduct. Notwithstanding the foregoing, in the event the Employee engages in Misconduct, as defined below, before or after the Employee's termination date but prior to receiving all of the payments described in this Section 1, the Company may cease making payments to the Employee under this Section 1, and the Company shall have no further obligations with respect to any amounts under this Agreement. For purposes of this Section 1(f), "Misconduct" shall mean (i) the final conviction of any felony, or (ii) the carrying out of any activity or the making of any public statement which materially diminishes the good name and standing of any Southern Entity or materially and untruthfully brings one or all of the Southern Entities into contempt, ridicule or materially and reasonably shocks or offends the community in which a Southern Entity is located.

2. Sharing of Expense. In the event that the Employee is employed at more than one subsidiary or affiliate of Southern, the liability for amounts paid under this Agreement shall be apportioned so that each such company is obligated in accordance with this Section 2 to cover their percentage of the total liability as determined below. Each company's share of the liability shall be calculated by multiplying the Payment by a fraction where the numerator of such fraction is the base rate of pay received by the Employee at the respective company on his date of termination of employment or transfer, as applicable, multiplied by the Accredited Service as defined in the Pension Plan earned by the Employee at the respective company and where the denominator of such fraction is the sum of all numerators calculated for each respective company by which the Employee has been employed.

3. Transfer of Employment to a Southern Subsidiary or Affiliate. In the event that Employee's employment by the Company is terminated and Employee shall become immediately re-employed by a subsidiary or an affiliate of Southern, the Company shall assign this Agreement pursuant to an Assignment Agreement substantially in the form of Exhibit 1 attached hereto, and such assignee shall become the "Company" for all purposes hereunder. Such subsidiary or affiliate shall accept such assignment, but if for any reason this does not occur, Southern shall accept such assignment. In the event of such assignment, liability for any amounts to be paid under this Agreement shall be shared pro rata by the Company, Southern, SCS and any such assignee (collectively "Contract Obligors") based upon the allocation methodology set forth in Section 2.

4. Business Protection Provisions.

(a) Preamble. As a material inducement to the Southern Parties to enter into this Agreement, and the recognition of the valuable experience, knowledge and proprietary information Employee gained from his employment with the Company, Employee warrants and agrees he will abide by and adhere to the following business protection provisions in this Section 4.

(b) Definitions. For purposes of this Section 4, the following terms shall have the following meanings:

(i) "Competitive Position" shall mean any employment, consulting, advisory, directorship, agency, promotional or independent contractor arrangement between Employee and any Entity (as defined below) engaged

wholly or in material part in the business that the Company is engaged in whereby Employee is required to or does perform services on behalf of or for the benefit of such Entity which are substantially similar to the services Employee participated in or directed while employed by the Company or any other Southern Entity.

(ii) " Confidential Information " shall mean the proprietary or confidential data, information, documents or materials (whether oral, written, electronic or otherwise) belonging to or pertaining to the Company or any of the other Southern Entities, other than "Trade Secrets" (as defined below), which is of tangible or intangible value to any of the Southern Entities and the details of which are not generally known to the competitors of the Southern Entities. Confidential Information shall also include: (A) any items that any of the Southern Entities have marked "CONFIDENTIAL" or some similar designation or are otherwise identified as being confidential; (B) all non-public information known by or in the possession of Employee related to or regarding any proceedings involving or related to the Southern Entities before any federal or state regulatory agencies; and (C) all communications, research, analysis, reports, opinions, recommendations and presentations prepared, reviewed, edited or possessed by Employee at any time during his employment, whether marked Confidential or not, which relate to electric utilities, electric generation or transmission in the United States, or the building, acquisition or ownership of electric utility assets in the United States.

(iii) " Entity " or " Entities " shall mean any person, business, individual, partnership, joint venture, agency, governmental agency, body or subdivision, association, firm, corporation, limited liability company or other entity of any kind.

(iv) " Territory " shall mean the service territory of the Southern Entities and those states contiguous to such service territory or otherwise connected through regional electric markets.

(v) " Trade Secrets " shall mean information or data of or about any of the Southern Entities, including, but not limited to, technical or non-technical data, formulas, patterns, compilations, programs, devices, methods, techniques,

drawings, processes, financial data, financial plans, product plans or lists of actual or potential customers or suppliers that: (A) derives economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use; and (B) is the subject of efforts that are reasonable under the circumstances to maintain its secrecy. Employee agrees that trade secrets include non-public information related to the rate making process of the Southern Entities and any other information which is defined as a "trade secret" under applicable law, regardless of the process through which Employee would have become aware of or possessed such information.

(vi) " Work Product " shall mean all tangible work product, memoranda, working papers, property, data, documentation, concepts or plans, inventions, improvements, techniques and processes (and drafts thereof) relating to the Southern Entities that were conceived, discovered, created, written, revised or developed by Employee during the term of his employment with SCS and the Company.

(c) Nondisclosure: Ownership of Proprietary Property .

(i) In recognition of the need of the Company to protect its legitimate business interests, Confidential Information and Trade Secrets, Employee hereby covenants and agrees that Employee shall regard and treat Trade Secrets and all Confidential Information as strictly confidential and wholly-owned by the Company and shall not, for any reason, in any fashion, either directly or indirectly, use, sell, lend, lease, distribute, license, give, transfer, assign, show, disclose, disseminate, reproduce, copy, misappropriate or otherwise communicate any such item or information to any third party Entity for any purpose other than in accordance with this Agreement or as required by applicable law: (A) with regard to each item constituting a Trade Secret, at all times such information remains a "trade secret" under applicable law, and (B) with regard to any Confidential Information, for a period of three (3) years following the Employee's date of Separation from Service (hereafter the "Restricted Period").

(ii) Employee shall exercise best efforts to ensure the continued confidentiality of all Trade Secrets and Confidential Information, and he shall immediately notify the Company of any unauthorized disclosure or use of any Trade Secrets or Confidential Information of which Employee becomes aware. Employee shall assist the Company, to the extent necessary, in the protection of or procurement of any intellectual property protection or other rights in any of the Trade Secrets or Confidential Information.

(iii) All Work Product shall be owned exclusively by the Company. To the greatest extent possible, any Work Product shall be deemed to be "work made for hire" (as defined in the Copyright Act, 17 U.S.C.A. § 101 et seq., as amended), and Employee hereby unconditionally and irrevocably transfers and assigns to the Company all right, title and interest Employee currently has or may have by operation of law or otherwise in or to any Work Product, including, without limitation, all patents, copyrights, trademarks (and the goodwill associated therewith), trade secrets, service marks (and the goodwill associated therewith) and other intellectual property rights. Employee agrees to execute and deliver to the Company any transfers, assignments, documents or other instruments which the Company may deem necessary or appropriate, from time to time, to protect the rights granted herein or to vest complete title and ownership of any and all Work Product, and all associated intellectual property and other rights therein, exclusively in the Company.

(d) Non-Interference with Employees. Employee covenants and agrees that during the Restricted Period he will not, either directly or indirectly, alone or in conjunction with any Entity: (i) actively recruit, solicit, attempt to solicit, or induce any person who, during such Restricted Period, or within one year prior to his date of Separation from Service, was an exempt employee of the Company or any of its subsidiaries, or was an officer of any of the other Southern Entities to leave or cease such employment for any reason whatsoever; or (ii) hire or engage the services of any such person described in Section 4(d)(i) in any business substantially similar or competitive with that in which the Southern Entities were engaged during his employment.

(e) Non-Interference with Customers.

(i) Employee acknowledges that in the course of employment, he has learned about the Company's business, services, materials, programs, plans, processes, and products and the manner in which they are developed, marketed, serviced and provided. Employee knows and acknowledges that the Company has invested considerable time and money in developing its business, services, materials, programs, plans, processes, products and marketing techniques and that they are unique and original. Employee further acknowledges that the Company must keep secret all pertinent information divulged to Employee regarding the Company's business concepts, services, materials, ideas, programs, plans and processes, products and marketing techniques, so as not to aid the Company's competitors. Accordingly, the parties agree that the Company is entitled to the following protection, which Employee agrees is reasonable:

(ii) Employee covenants and agrees that for a period of two (2) years following his date of Separation from Service, he will not, on his own behalf or on behalf of any Entity, solicit, direct, appropriate, call upon, or initiate communication or contact with any Entity or any representative of any Entity, with whom Employee had contact during his employment, with a view toward the sale or the providing of any product, equipment or service sold or provided or under development by the Company during the period of two (2) years immediately preceding the date of Employee's date of Separation from Service. The restrictions set forth in this Section shall apply only to Entities with whom Employee had actual contact during the two (2) years prior to Employee's date of Separation from Service with a view toward the sale or providing of any product, equipment or service sold, provided, or under development by the Company.

(f) Non-Interference with Business.

(i) Employee and the Company expressly covenant and agree that the scope, territorial, time and other restrictions contained in this entire Agreement constitute the most reasonable and equitable restrictions possible to protect the business interests of the Company given: (A) the business of the Company; (B) the competitive nature of the Company's industry; and (C) that Employee's skills

are such that he could easily find alternative, commensurate employment or consulting work in his field which would not violate any of the provisions of this Agreement.

(ii) Employee covenants and agrees to not obtain or work in a Competitive Position within the Territory for a period of two (2) years from the date of Separation from Service, except as expressly approved by the Chief Executive Officer of the Company.

5. Publicity; No Disparaging Statement . Except as otherwise provided in Section 9 hereof, Employee and the Company covenant and agree that they shall not engage in any communications which shall disparage one another or interfere with their existing or prospective business relationships. Such communications include, but are not necessarily limited to, remarks, comments, observations, analysis, opinions, statements, whether solicited or unsolicited, written or verbal, which reflect in any manner on the market, operating, financial, communications, people or other business strategies or actions of the Southern Entities, and their officers, directors, employees and agents.

6. No Employment . Employee agrees that he shall not unilaterally seek re-employment as an employee, temporary employee, leased employee or independent contractor with any of the Southern Entities, for a period of two (2) years following the Employee's date of Separation from Service. Further, neither the Company nor any of the other Southern Entities shall rehire Employee as an employee, temporary employee, leased employee or independent contractor for a period of two (2) years following Employee's date of Separation from Service, unless a necessary business reason exists for rehiring Employee and a committee, comprised of (a) an officer from the business unit of the Southern Entity seeking to rehire Employee and (b) the Chief Executive Officer of the Company, approves of such rehiring.

7. Return of Materials . By no later than the Employee's date of Separation from Service, Employee agrees to return to the Company all property of the Company and other Southern Entities, including but not limited to data, lists, information, memoranda, documents, identification cards, parking cards, keys, computers, fax machines, beepers, phones, files and any and all written or descriptive materials of any kind belonging or relating to the Company or any other Southern Entity, including, without limitation, any originals, copies and abstracts

containing any Work Product, intellectual property, Confidential Information and Trade Secrets in Employee's possession or control.

8. Cooperation. The parties agree that as a result of Employee's duties and activities during his employment, Employee's reasonable availability may be necessary for the Company to meaningfully respond to or address actual or threatened litigation, or government inquiries or investigations, or required filings with state, federal or foreign agencies (hereinafter "Company Matters"). Upon request of the Company, and at any point following Employee's date of Separation from Service, Employee will make himself available to the Company for reasonable periods not inconsistent with his future employment, if any, by other Entities and will cooperate with the Company's agents and attorneys as reasonably required by such Company Matters. The Company will reimburse Employee for any reasonable out-of-pocket expenses associated with providing such cooperation.

9. Confidentiality and Legal Process. Employee represents and agrees that he will keep the terms, amount and fact of this Agreement confidential and that he will not hereafter disclose any information concerning this Agreement to anyone other than his personal agents, including, but not limited to, any past, present, or prospective employee or applicant for employment with the Company. Notwithstanding the foregoing, nothing in this Agreement is intended to prohibit Employee from performing any duty or obligation that shall arise as a matter of law. Specifically, Employee shall continue to be under a duty to truthfully respond to any legal and valid subpoena or other legal process. This Agreement is not intended in any way to proscribe Employee's right and ability to provide information to any federal, state or local government in the lawful exercise of such governments' governmental functions.

10. Successors and Assigns; Applicable Law. This Agreement shall be binding upon and inure to the benefit of Employee and his heirs, administrators, representatives, executors, successors and assigns, and shall be binding upon and inure to the benefit of the Contract Obligors and their officers, directors, employees, agents, shareholders, parent corporation, and affiliates, and their respective predecessors, successors, assigns, heirs, executors and administrators and each of them, and to their heirs, administrators, representatives, executors, successors, and assigns. This Agreement shall be construed and interpreted in accordance with the laws of the State of Alabama (without giving effect to principles of conflicts of laws), to the extent such laws are not otherwise superseded by the laws of the United States.

11. Complete Agreement . This Agreement shall constitute the full and complete agreement between the parties concerning its subject matter and fully supersedes any and all other prior agreements or understandings between the parties concerning the subject matter hereof, including but not limited to that certain Deferred Compensation Agreement entered into April 12, 2004. This Agreement shall not be modified or amended except by a written instrument signed by both Employee and an authorized representative of the Company and Southern.

12. Severability . The unenforceability or invalidity of any particular provision of this Agreement shall not affect its other provisions, and to the extent necessary to give such other provisions effect, they shall be deemed severable. If any of the provisions of this Agreement are determined by any court of law or equity with jurisdiction over this matter to be unreasonable or unenforceable, in whole or in part, as written, the parties hereby consent to and affirmatively request that said court reform the provision so as to be reasonable and enforceable and that said court enforce the provision as reformed. Employee acknowledges and agrees that the covenants and agreements contained in this Agreement, including, without limitation, the covenants and agreements contained in Sections 4, 5, 6, 7 and 8 shall be construed as covenants and agreements independent of each other or any other contract between the parties hereto and that the existence of any claim or cause of action by Employee, whether predicated upon this Agreement or any other contract, shall not constitute a defense to the enforcement by the Southern Parties of said covenants and agreements.

13. Waiver of Breach; Specific Performance . The waiver of a breach of any provision of this Agreement shall not operate or be construed as a waiver of any other breach. Each of the parties to this Agreement will be entitled to enforce its or his rights under this Agreement, specifically, to recover damages by reason of any breach of any provision of this Agreement and to exercise all other rights existing in its or his favor. The parties hereto agree and acknowledge that money damages may not be an adequate remedy for any breach of the provisions of this Agreement and that any party may in its or his sole discretion apply to any court of law or equity of competent jurisdiction for specific performance or injunctive relief in order to enforce or prevent any violations of the provisions of this Agreement.

14. Unsecured General Creditor . The Contract Obligors shall neither reserve nor specifically set aside funds for the payment of its obligations under this Agreement, and such

obligations shall be paid solely from the general assets of the Contract Obligors. Notwithstanding that Employee may be entitled to receive the value of his benefit under the terms and conditions of this Agreement, the assets from which such amount may be paid shall at all times be subject to the claims of the Contract Obligors' creditors.

15. No Effect on other Arrangements. It is expressly understood and agreed that the payments made in accordance with this Agreement are in addition to any other benefits or compensation to which Employee may be entitled or for which he may be eligible, whether funded or unfunded, by reason of his employment with the Contract Obligors.

16. Tax Withholding and Implications. There shall be deducted from any payment under this Agreement the amount of any tax required by any governmental authority to be withheld and paid over by the Company to such governmental authority for the account of Employee.

17. Notices. All notices required, necessary or desired to be given pursuant to this Agreement shall be in writing and shall be effective when delivered or on the third day following the date upon which such notice is deposited, postage prepaid, in the United States mail, certified return receipt requested, and addressed to the party at the address set forth below:

If to Employee:

Mark A. Crosswhite
3505 Brookwood Road
Birmingham, Alabama 35223

If to the Company:

Gordon Martin
Senior Vice President and General Counsel
Alabama Power Company
Bin # 18N-0001 CORP HDQS
600 North 18th Street
Birmingham, Alabama 35203

18. Compensation and/or Earnings. Any compensation paid on behalf of Employee under this Agreement shall not be considered "compensation," as such term is defined in The Southern Company Employee Savings Plan or "earnings" as such term is defined in the Pension Plan. Payments under this Agreement shall not be considered wages, salaries or compensation under any other employee benefit plan of the Company or any other Southern Entity.

19. No Guarantee of Employment. No provision of this Agreement shall be construed to affect in any manner the existing rights of the Company to suspend, end, alter, or modify, whether or not for cause, the employment relationship of Employee and the Company.

20. Interpretation . The judicial body interpreting this Agreement shall not more strictly construe the terms of this Agreement against one party, it being agreed that both parties and/or their attorneys or agents have negotiated and participated in the preparation hereof.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the date first above written.

"SOUTHERN"

THE SOUTHERN COMPANY

By: /s/Charles D. McCrary

Its: Executive Vice President

"SCS"

SOUTHERN COMPANY SERVICES, INC.

By: /s/C. Alan Martin

Its: President & CEO

"COMPANY"

ALABAMA POWER COMPANY

By: /s/Charles D. McCrary

Its: President and CEO

"EMPLOYEE"

MARK A. CROSSWHITE

/s/Mark A. Crosswhite

Exhibit 1

FORM OF ASSIGNMENT AGREEMENT

THIS ASSIGNMENT AGREEMENT by and between Alabama Power Company ("Assignor") and ____________________ ("Assignee") dated this ____ day of ___________, 20__.

WHEREAS Assignor entered into that certain Deferred Compensation Agreement by and between Assignor, The Southern Company, Southern Company Services, Inc. and Mark A. Crosswhite ("Employee") on or about ______________, 20__ (the "DCA");

WHEREAS Employee, Assignor and Assignee desire for Employee to transfer his employment from Assignor to Assignee; and

WHEREAS Assignor desires to assign its rights and further obligations under the DCA to Assignee and Assignee desires to accept such assignment.

NOW THEREFORE, in consideration of the premises, and the agreements of the parties set forth in this agreement, and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto, intending to be legally bound, hereby covenant and agree as follows:

1. Pursuant to the terms of the DCA, Assignor assigns its further obligations under the DCA to Assignee and Assignee accepts such assignment; provided, however, that such assignment does not relieve Assignor of any accrued obligations to Employee or any other party under the DCA as of the date of this Assignment Agreement.

IN WITNESS WHEREOF parties hereto have executed this Agreement as follows:

ASSIGNOR

ALABAMA POWER COMPANY

By: ________________________________
Its: ________________________________
Date ________________________________

ASSIGNEE

COMPANY

By: ________________________________
Its: ________________________________
Date ________________________________

Exhibit 10(a)18

FIRST AMENDMENT TO THE SOUTHERN COMPANY SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN

WHEREAS, the Board of Directors of Southern Company Services, Inc. (the "Company") heretofore established and adopted the Southern Company Supplemental Executive Retirement Plan, as amended and restated effective June 30, 2016 (the "Plan"); and

WHEREAS, the Company has authorized an amendment to the Plan to implement changes necessary to coordinate the Plan provisions with design changes occurring to the Southern Company Pension Plan; and

WHEREAS, the Company desires to amend the Plan to add small benefit pay-out features; and

WHEREAS, Section 6.2 of the Plan provides in relevant part that the Plan may be amended or modified at any time by the Company.

NOW, THEREFORE, effective as the date set forth below, the Company hereby amends the Plan as follows:

1.

Effective January 1, 2017, the Plan is hereby amended by adding the following new Section 5.9:

5.9 Payment of Small Pension Benefits .

(a) Cash Out . With respect to a Participant who retires under the terms of the Plan and has a Separation from Service on or after July 1, 2017, as permitted under Treas. Reg. §1.409A-3(j)(4)(v) and subject to paragraph (b) below, the Administrative Committee in its sole discretion may pay in a single lump sum the entire SERP Benefit of a Participant at the time when the first installment of the SERP Benefit would otherwise be paid under Section 5.2(b)(1), provided that, (1) the Company evidences such decision in writing no later than the date of payment to the Participant, (2) the payment results in the termination and liquidation of the Participant's interest under the Plan and under all other plans maintained by the Company and its affiliates that are required to be aggregated with the Plan under Code Section 409A, and (3) the total payment amount with respect to the SERP Benefit and the benefit of any other plan required to be aggregated with the Plan under Code Section 409A does not exceed the dollar limit under Code Section 402(g)(1)(B) applicable for the year of payment. For purposes of paragraph (a)(3) above, the SERP Benefit will be calculated as the Single-Sum Amount provided in Section 2.24 of the Plan.

(b) Rules of General Application . (1) Notwithstanding paragraph (a) above, if a Participant is a Key Employee, such Participant shall be subject to

the Key-Employee Delay, if applicable, and the payment of the lump sum following Separation from Service shall be as of the first day of the seventh full calendar month following the Participant's Separation from Service. (2) The SERP Benefit of a Participant who has made an election under Section 5.3 to receive an annuity form of benefit may not be paid out under this Section 5.9. (3) Any Participant's benefit paid under this Section 5.9 shall be adjusted for payment of FICA consistent with the terms of this Plan.

2.

Except as amended herein by this First Amendment, the Plan shall remain in full force and effect.

IN WITNESS WHEREOF, the Company, through its duly authorized officer, has adopted this First Amendment to the Southern Company Supplemental Executive Retirement Plan, as amended and restated as of June 30, 2016 this 19th day of December, 2016.

SOUTHERN COMPANY SERVICES, INC.

By: /s/Stacy Kilcoyne

Its: Human Resources Vice President

Attest:

By: /s/Laura O. Hewett

Its: Assistant Secretary

Exhibit 10(a)19

FIRST AMENDMENT TO THE SOUTHERN COMPANY SUPPLEMENTAL BENEFIT PLAN

WHEREAS, the Board of Directors of Southern Company Services, Inc. (the "Company") heretofore established and adopted the Southern Company Supplemental Benefit Plan, as amended and restated effective June 30, 2016 (the "Plan"); and

WHEREAS, the Company has authorized an amendment to the Plan to implement changes necessary to coordinate the Plan provisions with design changes occurring to the Southern Company Pension Plan; and

WHEREAS, the Company desires to amend the Plan to add small benefit pay-out features; and

WHEREAS, Section 6.2 of the Plan provides in relevant part that the Plan may be amended or modified at any time by the Company.

NOW, THEREFORE, effective as the date set forth below, the Company hereby amends the Plan as follows:

1.

Effective January 1, 2017, the Plan is hereby amended by adding the following new Section 5.11:

5.11 Payment of Small Pension Benefits and Non-Pension Benefits .

(a) Cash Out . With respect to a Participant who retires under the terms of the Plan and has a Separation from Service on or after July 1, 2017, as permitted under Treas. Reg. §1.409A-3(j)(4)(v) and subject to paragraph (c) below, the Administrative Committee in its sole discretion may pay in a single lump sum the entire Pension Benefit and/or separately the Non-Pension Benefit of a Participant the date when (1) in the case of the Pension Benefit, the first installment of such Pension Benefit would have otherwise be paid under Section 5.2(b) and (2) in the case of the Non-Pension Benefit, the payment would have commenced in accordance with the Participant's election under Section 5.5(a) of the Plan, provided that (3), (A) the Company evidences such decision in writing no later than the date of payment to the Participant, (B) the payment results in the termination and liquidation of the Participant's interest under the Plan and under all other plans maintained by the Company and its affiliates that are required to be aggregated with the Plan under Code Section 409A, (C) in the case of the Pension Benefit, the total payment amount of such Pension Benefit and the benefit of any other plan required to be aggregated with the Plan under Code Section 409A does not exceed the dollar limit under Code Section 402(g)(1)(B) applicable for the year of payment, and (D) in the case of the Non-Pension Benefit, the separate total payment amount with respect to such Non-Pension Benefit and the benefit of any other plan required to be

aggregated with the Plan under Code Section 409A does not exceed the dollar limit under Code Section 402(g)(1)(B) applicable for the year of payment. For purposes of paragraph (a)(3)(C) above, the Pension Benefit will be calculated as the Single-Sum Amount provided in Section 2.34 of the Plan. For purposes of paragraph (a)(3)(D) above, the Non-Pension Benefit will be determined in accordance with Section 5.5(a) of the Plan. For the avoidance of doubt, the Pension Benefit and the Non-Pension Benefit under this Plan are not required to be aggregated for purposes of paragraph (a)(3)(B) above because each is considered to be a different type of deferred compensation plan under Code Section 409A.

(b) Payment of Small Benefit. Subject to paragraph (c) below, with respect to an Employee who first becomes a Participant in the Plan on or after January 1, 2017, and retires under the terms of the Plan and who has a Separation from Service on or after July 1, 2017, (1) if the Single-Sum Amount plus Earnings, if any, of such Participant's Pension Benefit calculated as provided in Sections 2.34 and 5.2 of the Plan is not greater than $50,000 at the time when the first installment of the Pension Benefit would otherwise be paid after retirement under Section 5.2(b)(1), such Pension Benefit shall be paid as a single lump sum at that time and/or (2) if the value of such Participant's Non-Pension Benefit Account is not greater than $50,000 as of his Separation from Service and such Participant has elected an installment form of payment, such Non-Pension Benefit shall be paid in accordance with Section 5.5(a). The Company in applying this Section 5.11(b) must treat all similarly situated Participants on a reasonably equivalent basis.

(c) Rules of General Application. (1) Notwithstanding paragraphs (a) and (b) above, if a Participant is a Key Employee, such Participant shall be subject to the Key-Employee Delay, if applicable, and the payment of the lump sum following Separation from Service shall be as of the first day of the seventh full calendar month following the Participant's Separation from Service. (2) The Pension Benefit of a Participant who has made an election under Section 5.3 to receive an annuity form of benefit may not be paid out under this Section 5.11. (3) Paragraph (b) above is inapplicable to Non-Pension Benefits governed by the Schedule of Provisions for Pre-2005 Non-Pension Benefits. (4) Any Participant's benefit paid under this Section 5.11 shall be adjusted for payment of FICA consistent with the terms of this Plan.

2.

Except as amended herein by this First Amendment, the Plan shall remain in full force and effect.

IN WITNESS WHEREOF, the Company, through its duly authorized officer, has adopted this First Amendment to the Southern Company Supplemental Benefit Plan, as amended and restated as of June 30, 2016 this 19th day of December, 2016.

SOUTHERN COMPANY SERVICES, INC.

By: /s/Stacy Kilcoyne

Its: Human Resources Vice President

Attest:

By: /s/Laura O. Hewett

Its: Assistant Secretary

Exhibit 10(e)21

MISSISSIPPI POWER COMPANY
PROMISSORY NOTE

November 10, 2015 Up to $375,000,000

FOR VALUE RECEIVED, MISSISSIPPI POWER COMPANY, a Mississippi corporation (the “Borrower”), hereby promises to pay on or before December 1, 2017 (the “Final Maturity Date”), to THE SOUTHERN COMPANY, a Delaware corporation (the “Holder”), the principal sum of up to THREE HUNDRED AND SEVENTY-FIVE MILLION DOLLARS ($375,000,000), together with interest on the principal amount, all as indicated in the records of the Holder and on the grid attached hereto.

Interest. Interest (calculated on the basis of a year of 360 days and the actual number of days elapsed) on this Promissory Note (this “Note”) shall be paid monthly in arrears, or if the Borrower fails to pay interest each month, such interest shall be included in the outstanding principal balance for purposes of calculating interest due to the extent permitted by applicable law. The interest rate on this Note shall be a floating rate equal to the Adjusted LIBOR Rate.

Adjusted LIBOR Rate. Interest shall be at a rate equal to the one-month London Interbank Offered Rate (“LIBOR”) plus the Applicable Percentage corresponding to the senior debt rating of the Borrower in effect from time to time as described below (the “Senior Debt Rating”):

Senior Debt Rating	Applicable Percentage
I. ≥ A- from S&P ≥ A3 from Moody’s ≥ A- from Fitch	1.375%
II. ≥ BBB+ but < A- from S&P ≥ Baa1 but < A3 from Moody’s ≥ BBB+ but < A- from Fitch	1.500%
III. ≥ BBB but < BBB+ from S&P ≥ Baa2 but < Baa1 from Moody’s ≥ BBB but < BBB+ from Fitch	1.750%
IV. < BBB from S&P < Baa2 from Moody’s < BBB from Fitch unrated by any two of S&P, Moody’s or Fitch	2.000%

Notwithstanding the above, if at any time there is a split in Senior Debt Ratings among Standard & Poor’s Financial Services LLC, a division of McGraw-Hill Financial, Moody’s Investors Service, Inc., and Fitch Ratings, Inc., or any successor or assignee of the business of

the foregoing in the business of rating securities and (a) two Senior Debt Ratings are equal and higher than the third Senior Debt Rating, the higher Senior Debt Ratings will apply, (b) two Senior Debt Ratings are equal and lower than the third Senior Debt Rating, the lower Senior Debt Ratings will apply or (c) no Senior Debt Ratings are equal, the intermediate Senior Debt Rating will apply. In the event that the Borrower shall maintain Senior Debt Ratings from only two of S&P, Moody's or Fitch and there is a split in such Senior Debt Ratings, (i) in the event of a single level split, the higher Senior Debt Rating (i.e. the lower pricing) will apply and (ii) in the event of a multiple level split, one level below the higher Senior Debt Rating will apply.

Repayment. The Borrower shall be entitled, at any time and from time to time, without the consent of the Holder and without paying any penalty or premium therefor, to prepay all or any portion or portions of the outstanding principal balance. The outstanding principal balance shall be payable in full on the Final Maturity Date, together with all accrued interest thereon.

Records. All long-term borrowings by the Borrower from the Holder from the date hereof and all payments on account of principal hereof shall be recorded by the Holder in its books and records and endorsed on the grid attached hereto and made a part hereof; provided, however, that no failure to keep or any error in such records or endorsements shall affect the obligations of the undersigned hereunder.

Payment by the Borrower to the Holder pursuant to this Note shall be made without set-off or counterclaim, at the Holder's office located in Atlanta, Georgia, or at any other place designated by the Holder in writing.

Representations and Warranties. The Borrower hereby represents and warrants: (i) that it is a corporation duly organized and existing under the laws of the State of Mississippi, is duly qualified to carry on its business as a corporation under the laws of the State of Mississippi, is duly qualified to carry on its business as a foreign corporation under the laws of the State of Alabama, and has due corporate authority to carry on the public utility business in which it is engaged and to own and operate the properties used by it in such business; (ii) that the execution, delivery and performance of this Note are within the power of the Borrower and have been duly authorized by all necessary action of the board of directors of the Borrower; (iii) that it has duly executed and delivered this Note; (iv) that this Note constitutes the legal, valid and binding obligations of the Borrower, enforceable against the Borrower in accordance with its terms; and (v) that the Borrower's execution, delivery and performance of this Note do not require the consent of any other party.

Events of Default. If any of the following events shall occur, such event shall constitute an event of default ("Event of Default") under this Note: (i) the Borrower shall fail to pay when due any payment required hereunder and such failure shall continue for five (5) or more business days; (ii) (A) a court or governmental agency having jurisdiction in the premises shall enter a decree or order for relief in respect of the Borrower in an involuntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect, or appoint a receiver, liquidator, assignee, custodian, trustee, sequestrator or similar official of the Borrower or for any substantial part of its property or ordering the winding up or liquidation of its affairs; or (B) an involuntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect is commenced against the Borrower and such petition remains unstayed and in

effect for a period of sixty (60) consecutive days; or (C) the Borrower shall commence a voluntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect, or consent to the entry of an order for relief in an involuntary case under any such law, or consent to the appointment or taking possession by a receiver, liquidator, assignee, custodian, trustee, sequestrator or similar official of such person or any substantial part of its property or make any general assignment for the benefit of creditors; or (D) the Borrower shall admit in writing its inability to pay its debts generally as they become due or any action shall be taken by such person in furtherance of any of the aforesaid purposes; (iii) if an event of default shall occur under any other indebtedness of the Borrower in excess of $75,000,000; or (iv) one or more judgments, orders or decrees shall be entered against the Borrower involving a liability of $75,000,000 or more, in the aggregate (to the extent not paid or covered by insurance provided by a carrier who has acknowledged coverage) and such judgments, orders or decrees shall continue unsatisfied, undischarged and unstayed for a period of at least thirty (30) days after the last day on which such judgment, order or decree becomes final and unappealable and, where applicable, with the status of a judicial lien.

Upon the occurrence of any Event of Default, the Holder shall be entitled to accelerate the payment of the principal of and all accrued and unpaid interest on this Note and declare the same to be immediately due and payable and shall also have available to it all rights and remedies permitted by applicable law.

In the event that, upon an Event of Default hereunder, the Holder deems it necessary or proper to employ an attorney to enforce collection of any unpaid balance hereunder, the Borrower agrees to pay the Holder’s reasonable attorney’s fees and collection costs.

Exercising Rights. No delay or omission on the part of the Holder in exercising any right hereunder shall operate as a waiver of such right or any other right under this Note. A waiver of any right or remedy on any one occasion shall not be construed as a bar to or waiver of any right or remedy on any future occasion.

Waiver. The Borrower hereby waives presentment, demand for payment, notice or dishonor and all other notices or demands in connection with the delivery, acceptance, performance, default or endorsement of this Note.

Governing Law. This Note shall be governed by, and construed in accordance with, the laws of the State of New York. In the event this Note is collected by law or through an attorney at law, the Borrower agrees to pay all reasonable attorney’s fees and costs of collection actually incurred by the Holder.

IN WITNESS WHEREOF, the Borrower has caused this Note to be executed as of the date first above written.

MISSISSIPPI POWER COMPANY,
a Mississippi corporation

By: _/s/Moses H. Feagin___________
Moses H. Feagin
Vice President, Treasurer and Chief Financial Officer

Date	Principal Borrowed	Principal Repaid	Notation

Exhibit 10(e)22

MISSISSIPPI POWER COMPANY
AMENDED AND RESTATED PROMISSORY NOTE

December 22, 2015 $301,126,146.39

FOR VALUE RECEIVED, MISSISSIPPI POWER COMPANY, a Mississippi corporation (the “Borrower”), hereby promises to pay on or before December 1, 2017 (the “Final Maturity Date”), to THE SOUTHERN COMPANY, a Delaware corporation (the “Holder”), the principal sum of THREE HUNDRED ONE MILLION ONE HUNDRED TWENTY-SIX THOUSAND ONE HUNDRED FORTY-SIX DOLLARS AND THIRTY-NINE CENTS ($301,126,146.39), together with interest on the principal amount from June 4, 2015, all as indicated in the records of the Holder and on the grid attached hereto.

This Amended and Restated Promissory Note (this “Note”) amends and restates in its entirety that certain promissory note, dated June 3, 2015, issued by the Borrower to the Holder.

Interest. Interest (calculated on the basis of a year of 360 days and the actual number of days elapsed) on this Note shall be paid monthly in arrears, or if the Borrower fails to pay interest each month, such interest shall be included in the outstanding principal balance for purposes of calculating interest due to the extent permitted by applicable law. The interest rate on this Note shall be a floating rate equal to the Adjusted LIBOR Rate.

Adjusted LIBOR Rate. Interest shall be at a rate equal to the one-month London Interbank Offered Rate (“LIBOR”) plus the Applicable Percentage corresponding to the senior debt rating of the Borrower in effect from time to time as described below (the “Senior Debt Rating”):

Senior Debt Rating	Applicable Percentage
I. ≥ A- from S&P ≥ A3 from Moody’s ≥ A- from Fitch	1.375%
II. ≥ BBB+ but < A- from S&P ≥ Baa1 but < A3 from Moody’s ≥ BBB+ but < A- from Fitch	1.500%
III. ≥ BBB but < BBB+ from S&P ≥ Baa2 but < Baa1 from Moody’s ≥ BBB but < BBB+ from Fitch	1.750%
IV. < BBB from S&P < Baa2 from Moody’s < BBB from Fitch unrated by any two of S&P, Moody’s or Fitch	2.000%

Notwithstanding the above, if at any time there is a split in Senior Debt Ratings among Standard & Poor's Financial Services LLC, a division of McGraw-Hill Financial, Moody's Investors Service, Inc., and Fitch Ratings, Inc., or any successor or assignee of the business of the foregoing in the business of rating securities and (a) two Senior Debt Ratings are equal and higher than the third Senior Debt Rating, the higher Senior Debt Ratings will apply, (b) two Senior Debt Ratings are equal and lower than the third Senior Debt Rating, the lower Senior Debt Ratings will apply or (c) no Senior Debt Ratings are equal, the intermediate Senior Debt Rating will apply. In the event that the Borrower shall maintain Senior Debt Ratings from only two of S&P, Moody's or Fitch and there is a split in such Senior Debt Ratings, (i) in the event of a single level split, the higher Senior Debt Rating (i.e. the lower pricing) will apply and (ii) in the event of a multiple level split, one level below the higher Senior Debt Rating will apply.

Repayment. The Borrower shall be entitled, at any time and from time to time, without the consent of the Holder and without paying any penalty or premium therefor, to prepay all or any portion or portions of the outstanding principal balance. The outstanding principal balance shall be payable in full on the Final Maturity Date, together with all accrued interest thereon.

Records. All long-term borrowings by the Borrower from the Holder from June 3, 2015 and all payments on account of principal hereof shall be recorded by the Holder in its books and records; provided, however, that no failure to keep or any error in such records or endorsements shall affect the obligations of the undersigned hereunder.

Payment by the Borrower to the Holder pursuant to this Note shall be made without set-off or counterclaim, at the Holder's office located in Atlanta, Georgia, or at any other place designated by the Holder in writing.

Representations and Warranties. The Borrower hereby represents and warrants: (i) that it is a corporation duly organized and existing under the laws of the State of Mississippi, is duly qualified to carry on its business as a corporation under the laws of the State of Mississippi, is duly qualified to carry on its business as a foreign corporation under the laws of the State of Alabama, and has due corporate authority to carry on the public utility business in which it is engaged and to own and operate the properties used by it in such business; (ii) that the execution, delivery and performance of this Note are within the power of the Borrower and have been duly authorized by all necessary action of the board of directors of the Borrower; (iii) that it has duly executed and delivered this Note; (iv) that this Note constitutes the legal, valid and binding obligations of the Borrower, enforceable against the Borrower in accordance with its terms; and (v) that the Borrower's execution, delivery and performance of this Note do not require the consent of any other party.

Events of Default. If any of the following events shall occur, such event shall constitute an event of default ("Event of Default") under this Note: (i) the Borrower shall fail to pay when due any payment required hereunder and such failure shall continue for five (5) or more business days; (ii) (A) a court or governmental agency having jurisdiction in the premises shall enter a decree or order for relief in respect of the Borrower in an involuntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect, or appoint a receiver, liquidator, assignee, custodian, trustee, sequestrator or similar official of the Borrower or for any substantial part of its property or ordering the winding up or liquidation of its affairs; or (B) an

involuntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect is commenced against the Borrower and such petition remains unstayed and in effect for a period of sixty (60) consecutive days; or (C) the Borrower shall commence a voluntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect, or consent to the entry of an order for relief in an involuntary case under any such law, or consent to the appointment or taking possession by a receiver, liquidator, assignee, custodian, trustee, sequestrator or similar official of such person or any substantial part of its property or make any general assignment for the benefit of creditors; or (D) the Borrower shall admit in writing its inability to pay its debts generally as they become due or any action shall be taken by such person in furtherance of any of the aforesaid purposes; (iii) if an event of default shall occur under any other indebtedness of the Borrower in excess of $75,000,000; or (iv) one or more judgments, orders or decrees shall be entered against the Borrower involving a liability of $75,000,000 or more, in the aggregate (to the extent not paid or covered by insurance provided by a carrier who has acknowledged coverage) and such judgments, orders or decrees shall continue unsatisfied, undischarged and unstayed for a period of at least thirty (30) days after the last day on which such judgment, order or decree becomes final and unappealable and, where applicable, with the status of a judicial lien.

Upon the occurrence of any Event of Default, the Holder shall be entitled to accelerate the payment of the principal of and all accrued and unpaid interest on this Note and declare the same to be immediately due and payable and shall also have available to it all rights and remedies permitted by applicable law.

In the event that, upon an Event of Default hereunder, the Holder deems it necessary or proper to employ an attorney to enforce collection of any unpaid balance hereunder, the Borrower agrees to pay the Holder’s reasonable attorney’s fees and collection costs.

Exercising Rights. No delay or omission on the part of the Holder in exercising any right hereunder shall operate as a waiver of such right or any other right under this Note. A waiver of any right or remedy on any one occasion shall not be construed as a bar to or waiver of any right or remedy on any future occasion.

Waiver. The Borrower hereby waives presentment, demand for payment, notice or dishonor and all other notices or demands in connection with the delivery, acceptance, performance, default or endorsement of this Note.

Governing Law. This Note shall be governed by, and construed in accordance with, the laws of the State of New York. In the event this Note is collected by law or through an attorney at law, the Borrower agrees to pay all reasonable attorney’s fees and costs of collection actually incurred by the Holder.

IN WITNESS WHEREOF, the Borrower has caused this Note to be executed as of the date first above written.

MISSISSIPPI POWER COMPANY,
a Mississippi corporation

By: /s/Moses H. Feagin
Moses H. Feagin
Vice President, Treasurer and Chief Financial Officer

Exhibit 10(e)23

MISSISSIPPI POWER COMPANY
PROMISSORY NOTE

January 28, 2016 Up to $275,000,000

FOR VALUE RECEIVED, MISSISSIPPI POWER COMPANY, a Mississippi corporation (the "Borrower"), hereby promises to pay on or before December 1, 2017 (the "Final Maturity Date"), to THE SOUTHERN COMPANY, a Delaware corporation (the "Holder"), the principal sum of up to TWO HUNDRED AND SEVENTY-FIVE MILLION DOLLARS ($275,000,000), together with interest on the principal amount, all as indicated in the records of the Holder and on the grid attached hereto.

Interest. Interest (calculated on the basis of a year of 360 days and the actual number of days elapsed) on this Promissory Note (this "Note") shall be paid monthly in arrears, or if the Borrower fails to pay interest each month, such interest shall be included in the outstanding principal balance for purposes of calculating interest due to the extent permitted by applicable law. The interest rate on this Note shall be a floating rate equal to the Adjusted LIBOR Rate.

Adjusted LIBOR Rate. Interest shall be at a rate equal to the one-month London Interbank Offered Rate ("LIBOR") plus the Applicable Percentage corresponding to the senior debt rating of the Borrower in effect from time to time as described below (the "Senior Debt Rating"):

Senior Debt Rating	Applicable Percentage
I. ≥ A- from S&P ≥ A3 from Moody's ≥ A- from Fitch	1.375%
II. ≥ BBB+ but < A- from S&P ≥ Baa1 but < A3 from Moody's ≥ BBB+ but < A- from Fitch	1.500%
III. ≥ BBB but < BBB+ from S&P ≥ Baa2 but < Baa1 from Moody's ≥ BBB but < BBB+ from Fitch	1.750%
IV. < BBB from S&P < Baa2 from Moody's < BBB from Fitch unrated by any two of S&P, Moody's or Fitch	2.000%

Notwithstanding the above, if at any time there is a split in Senior Debt Ratings among Standard & Poor's Financial Services LLC, a division of McGraw-Hill Financial, Moody's Investors Service, Inc., and Fitch Ratings, Inc., or any successor or assignee of the business of

the foregoing in the business of rating securities and (a) two Senior Debt Ratings are equal and higher than the third Senior Debt Rating, the higher Senior Debt Ratings will apply, (b) two Senior Debt Ratings are equal and lower than the third Senior Debt Rating, the lower Senior Debt Ratings will apply or (c) no Senior Debt Ratings are equal, the intermediate Senior Debt Rating will apply. In the event that the Borrower shall maintain Senior Debt Ratings from only two of S&P, Moody's or Fitch and there is a split in such Senior Debt Ratings, (i) in the event of a single level split, the higher Senior Debt Rating (i.e. the lower pricing) will apply and (ii) in the event of a multiple level split, one level below the higher Senior Debt Rating will apply.

Repayment. The Borrower shall be entitled, at any time and from time to time, without the consent of the Holder and without paying any penalty or premium therefor, to prepay all or any portion or portions of the outstanding principal balance. The outstanding principal balance shall be payable in full on the Final Maturity Date, together with all accrued interest thereon.

Records. All long-term borrowings by the Borrower from the Holder from the date hereof and all payments on account of principal hereof shall be recorded by the Holder in its books and records and endorsed on the grid attached hereto and made a part hereof; provided, however, that no failure to keep or any error in such records or endorsements shall affect the obligations of the undersigned hereunder.

Payment by the Borrower to the Holder pursuant to this Note shall be made without set-off or counterclaim, at the Holder's office located in Atlanta, Georgia, or at any other place designated by the Holder in writing.

Representations and Warranties. The Borrower hereby represents and warrants: (i) that it is a corporation duly organized and existing under the laws of the State of Mississippi, is duly qualified to carry on its business as a corporation under the laws of the State of Mississippi, is duly qualified to carry on its business as a foreign corporation under the laws of the State of Alabama, and has due corporate authority to carry on the public utility business in which it is engaged and to own and operate the properties used by it in such business; (ii) that the execution, delivery and performance of this Note are within the power of the Borrower and have been duly authorized by all necessary action of the board of directors of the Borrower; (iii) that it has duly executed and delivered this Note; (iv) that this Note constitutes the legal, valid and binding obligations of the Borrower, enforceable against the Borrower in accordance with its terms; and (v) that the Borrower's execution, delivery and performance of this Note do not require the consent of any other party.

Events of Default. If any of the following events shall occur, such event shall constitute an event of default ("Event of Default") under this Note: (i) the Borrower shall fail to pay when due any payment required hereunder and such failure shall continue for five (5) or more business days; (ii) (A) a court or governmental agency having jurisdiction in the premises shall enter a decree or order for relief in respect of the Borrower in an involuntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect, or appoint a receiver, liquidator, assignee, custodian, trustee, sequestrator or similar official of the Borrower or for any substantial part of its property or ordering the winding up or liquidation of its affairs; or (B) an involuntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect is commenced against the Borrower and such petition remains unstayed and in

effect for a period of sixty (60) consecutive days; or (C) the Borrower shall commence a voluntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect, or consent to the entry of an order for relief in an involuntary case under any such law, or consent to the appointment or taking possession by a receiver, liquidator, assignee, custodian, trustee, sequestrator or similar official of such person or any substantial part of its property or make any general assignment for the benefit of creditors; or (D) the Borrower shall admit in writing its inability to pay its debts generally as they become due or any action shall be taken by such person in furtherance of any of the aforesaid purposes; (iii) if an event of default shall occur under any other indebtedness of the Borrower in excess of $75,000,000; or (iv) one or more judgments, orders or decrees shall be entered against the Borrower involving a liability of $75,000,000 or more, in the aggregate (to the extent not paid or covered by insurance provided by a carrier who has acknowledged coverage) and such judgments, orders or decrees shall continue unsatisfied, undischarged and unstayed for a period of at least thirty (30) days after the last day on which such judgment, order or decree becomes final and unappealable and, where applicable, with the status of a judicial lien.

Upon the occurrence of any Event of Default, the Holder shall be entitled to accelerate the payment of the principal of and all accrued and unpaid interest on this Note and declare the same to be immediately due and payable and shall also have available to it all rights and remedies permitted by applicable law.

In the event that, upon an Event of Default hereunder, the Holder deems it necessary or proper to employ an attorney to enforce collection of any unpaid balance hereunder, the Borrower agrees to pay the Holder’s reasonable attorney’s fees and collection costs.

Exercising Rights. No delay or omission on the part of the Holder in exercising any right hereunder shall operate as a waiver of such right or any other right under this Note. A waiver of any right or remedy on any one occasion shall not be construed as a bar to or waiver of any right or remedy on any future occasion.

Waiver. The Borrower hereby waives presentment, demand for payment, notice or dishonor and all other notices or demands in connection with the delivery, acceptance, performance, default or endorsement of this Note.

Governing Law. This Note shall be governed by, and construed in accordance with, the laws of the State of New York. In the event this Note is collected by law or through an attorney at law, the Borrower agrees to pay all reasonable attorney’s fees and costs of collection actually incurred by the Holder.

IN WITNESS WHEREOF, the Borrower has caused this Note to be executed as of the date first above written.

MISSISSIPPI POWER COMPANY,
a Mississippi corporation

By: /s/Moses .H. Feagin
Moses H. Feagin
Vice President, Treasurer and Chief Financial Officer

Date	Principal Borrowed	Principal Repaid	Notation

2017 Text – Code of Ethics
Safety and Health We work safely, and we watch out for each other. Our goal is for everyone to go home healthy, every day. We do not compromise on safety. We complete required training, and we report and correct unsafe situations. We keep our workplace safe for the well-being of employees, customers, contractors and the public. We also keep our workplace and work sites free from violence and prohibit the inappropriate use of alcohol and drugs.
Our Employees Our employees make this a great place to work. We work together as a team, and everyone contributes to our success. We recognize and reward performance. We treat each other with fairness, respect and dignity. We value and encourage different ideas and points of view. Inclusion and diversity are strengths that unlock our full potential. We are an equal opportunity employer. We do not tolerate inappropriate conduct, intimidation, harassment or discrimination on any basis, including race, color, religion, sex, national origin, age, disability, veteran status, genetic information, sexual orientation, or gender identity or expression.
Our Relationships We are known for the quality and value of our customer service. We tell the truth, keep our promises and deal fairly and ethically with others. Our goal is to establish and maintain relationships built on trust. This goal guides all our business decisions. It extends to our customers, employees, vendors, contractors, regulators, stockholders and neighbors. We work to preserve the highest standards of integrity and objectivity. We expect our business partners to operate with ethical standards and values similar to our own.
The Environment We take our environmental compliance responsibilities seriously. We support environmental stewardship efforts that protect and preserve our natural resources. The communities we serve are also home to our families and we strive to make them better.
Compliance with Laws and Regulations Our reputation for doing the right thing is a valuable asset. We respect and comply with all laws and regulations. We also comply with company policies and the Code of Ethics. We provide training and resources to meet these expectations.
Financial Integrity We are prudent with company funds. All business records and accounts will be complete, accurate and based on proper accounting principles. The records will be maintained as required by law and company policies. Any attempt to conceal, omit or make false entries in the records will not be tolerated. We maintain appropriate internal controls to prevent and detect fraud. We will make full, fair, correct and timely disclosures in financial reports and other public communications.

Conflict of Interest We avoid conflicts of interest. Our goal is to avoid even the appearance of a conflict between our work and personal interests. Company resources are for business purposes and company-approved activities. We do not use our position, company resources or information for personal benefit. We do not compete with the company using personal or outside businesses. Any potential conflicts of interest must be disclosed promptly to management.
Gifts and Entertainment We do not approve, accept or offer gifts, entertainment, or other favors unless they are a part of a reasonable business relationship. We use good judgment in offering hospitality to others to help preserve our reputation and that of our business partners. All gifts or entertainment given or accepted must be in compliance with all applicable laws and company policy.
Competitive Practices We compete fairly, and vigorously, on the basis of price, superior service and value. We do not restrain trade, competition, prices, terms or markets. We market, advertise and collect market data, fairly and honestly.
Confidential Information We respect and protect the confidential information of our company, customers, employees, vendors and partners. We do not use confidential information in ways that conflict with laws, regulations or contracts. We comply with copyright, patent and trademark rights.
Political Activities We value and encourage citizenship. Employees have the freedom to choose whether or not to support political candidates, parties or positions, or to engage in political activities. The company will not tolerate pressuring employees to participate in political activities. Company resources will not be used to support political candidates, parties or committees unless permitted by law and company policy, and when approved in advance by executive management. We do not offer or provide gifts or entertainment of any type, including meals and transportation, to any government employee or public official in the United States or internationally unless doing so is appropriate and legal. We never offer bribes or kickbacks. Federal and state rules regarding gifts and entertainment for public officials and government employees can vary widely. This is also true when dealing with international businesses.
Duty to Act All employees have a duty to act. We must promptly report any suspected violation of this Code, company policies or any applicable laws or regulations. There are many ways employees can report issues – even anonymously. We investigate concerns and take appropriate action. Employees are expected to cooperate in investigations. The company does not tolerate retaliation in any form, against anyone who fulfills their duty to act. Issues about questionable accounting practices, violations of internal accounting controls or auditing matters may be reported directly to the Southern Company Audit Committee.

Conclusion
Ethics means more than just obeying laws and following policies. It means taking personal responsibility to speak out when we see a possible violation of the Code.

Our Values and Code of Ethics challenge us to inspire and help others to act ethically. We should make the most of every opportunity to model the values and behavior that make this a great place to work.

This Code of Ethics applies to all employees, officers and board members of Southern Company, its subsidiaries and affiliates.

Annually, all employees are required to certify they received, read and will abide by the Code of Ethics, including their duty to act.

No waivers of the provisions of this Code of Ethics may be granted to board members, officers or employees without authorization from the appropriate compliance officer or in certain circumstances the Southern Company Board of Directors. Waivers will be disclosed as required by applicable law, regulation or rule.

This Code of Ethics is a statement of policies for individual and business conduct and does not create any contractual right to current or future employment, employee benefits, or other terms and conditions of employment.

Exhibit 21(a)

Subsidiaries of the Registrant [(1)]

Name of Company	Jurisdiction of Organization
The Southern Company	Delaware
Alabama Power Company	Alabama
Alabama Power Capital Trust V	Delaware
Alabama Property Company	Alabama
Southern Electric Generating Company	Alabama
Georgia Power Company	Georgia
Piedmont-Forrest Corporation	Georgia
Southern Electric Generating Company	Alabama
Gulf Power Company	Florida
Mississippi Power Company	Mississippi
Southern Power Company	Delaware
Mankato Energy Center, LLC	Delaware
Mankato Energy Center II, LLC	Delaware
Nacogdoches Power, LLC	Delaware
Southern Company – Florida LLC	Delaware
Southern Company – Oleander LLC	Delaware
SP Oleander I, LLC	Delaware
SP Oleander II, LLC	Delaware
Oleander Power Project, LP(3)	Florida
Southern Renewable Energy, Inc.	Delaware
BNB Lamesa Solar LLC	Delaware
East Pecos Solar, LLC	Delaware
Grant Plains Wind, LLC	Delaware
Grant Wind, LLC	Delaware
Grant County Interconnect, LLC	Delaware
Kay Wind, LLC	Delaware
Passadumkeag Windpark, LLC	Delaware
Salt Fork Wind, LLC	Delaware
Tyler Bluff Wind Project, LLC	Delaware
Southern Turner Renewable Energy, LLC (4)	Delaware
Adobe Solar, LLC	Delaware
Apex Nevada Solar, LLC	Delaware
Calipatria, LLC	Delaware
Campo Verde Solar, LLC	Delaware
Granville Solar, LLC	Delaware
Macho Springs Solar, LLC	Delaware
Macho Springs Solar 2, LLC	Delaware
Morelos Solar, LLC	Delaware
Rutherford Farm, LLC	North Carolina
Southern Turner Cimarron I, LLC	Delaware
Southern Turner Cimarron Capital, LLC	Delaware
Spectrum Nevada Solar, LLC	Delaware
Southern Renewable Partnerships, LLC	Delaware
Desert Stateline Holdings, LLC (5)	Delaware

Desert Stateline, LLC	Delaware
Lost Hills Blackwell Holdings, LLC (6)	Delaware
Lost Hills Solar Holdco, LLC	Delaware
Lost Hills Solar, LLC	Delaware
Blackwell Solar Holdings, LLC	Delaware
Blackwell Solar, LLC	Delaware
NS Solar Holdings, LLC (6)	Delaware
North Star Solar, LLC	Delaware
SG2 Holdings, LLC (6)	Delaware
SG2 Imperial Valley LLC	Delaware
BSP Holding Company, LLC (6)	Delaware
Boulder Solar Power Parent, LLC	Delaware
Boulder Solar Power, LLC	Delaware
Parrey Holding Company, LLC (6)	Delaware
Parrey Parent, LLC	Delaware
Parrey, LLC	Delaware
RE Roserock Holdings LLC (6)	Delaware
RE Roserock LLC	Delaware
RE Silverlake Holdings LLC (6)	Delaware
RE Garland Holdings LLC	Delaware
RE Garland LLC	Delaware
RE Garland A LLC	Delaware
RE Tranquility Holdings LLC (6)	Delaware
RE Tranquility LLC	Delaware
RE Tranquility BAAH LLC	Delaware
WWH, LLC (7)	Delaware
Wake Wind Class B Holdings LLC	Delaware
Wake Wind Holdings LLC	Delaware
Wake Wind Energy LLC	Delaware
Southern Company Gas	Georgia
Southern Company Gas Capital Corporation	Nevada
AGL Investments Inc.	Georgia
Sequent LLC	Georgia
Atlanta Gas Light Company	Georgia
Georgia Natural Gas Company	Georgia
SouthStar Energy Services LLC	Delaware
NUI Corporation	New Jersey
Pivotal Utility Holdings Inc. (8)	New Jersey
Ottawa Acquisition LLC	Illinois
Northern Illinois Gas Company (9)	Illinois
Southern Company Gas Investments, Inc.	Georgia
Southern Company Gas Pipeline Holdings LLC	Georgia
Evergreen Enterprise Holdings LLC	Georgia

(1) This information is as of December 31, 2016. In addition, this list omits certain subsidiaries pursuant to paragraph (b)(21)(ii) of Regulation S-K, Item 601.
(2) SP Oleander II LLC owns 99% and SP Oleander I LLC owns 1%.
(3) Grant County Interconnect, LLC owns 90.1% and Grant Plains Wind, LLC owns 9.1%.
(4) Southern Renewable Energy, Inc. owns 90%.
(5) Southern Renewable Partnership, LLC owns 100% of the class A membership interests and is entitled to 60% of all cash distributions.

(6) Southern Renewable Partnership, LLC owns 100% of the class A membership interests and is entitled to 51% of all cash distributions.
(7) Southern Renewable Partnership, LLC owns 90.1%.
(8) Includes operations of three natural gas utilities: Elizabethtown Gas (New Jersey), Florida City Gas (Florida), and Elkton Gas (Maryland)
(9) Doing business as Nicor Gas Company.

Exhibit 23(a)1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 2-78617, 33-54415, 33-58371, 33-60427, 333-44127, 333-118061, 333-166709, 333-174704, 333-174707, 333-204618, 333-208173, and 333-212783 on Form S-8 and Registration Statement Nos. 333-202410 and 333-202413 on Form S-3 of our reports dated February 21, 2017, relating to the consolidated financial statements and consolidated financial statement schedule of The Southern Company and Subsidiary Companies (which expresses an unqualified opinion and includes an explanatory paragraph regarding uncertainty relating to the rate recovery process with the Mississippi Public Service Commission regarding recovery of the Kemper Integrated Coal Gasification Combined Cycle), and the effectiveness of The Southern Company and Subsidiary Companies' internal control over financial reporting, appearing in this Annual Report on Form 10-K of The Southern Company for the year ended December 31, 2016.

/s/Deloitte & Touche LLP
Atlanta, Georgia
February 21, 2017

Exhibit 23(b)1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-194227 on Form S-3 of our reports dated February 21, 2017, relating to the financial statements and financial statement schedule of Alabama Power Company, appearing in this Annual Report on Form 10-K of Alabama Power Company for the year ended December 31, 2016.

/s/Deloitte & Touche LLP

Birmingham, Alabama
February 21, 2017

Exhibit 23(c)1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-209779 on Form S-3 of our reports dated February 21, 2017, relating to the financial statements and financial statement schedule of Georgia Power Company, appearing in this Annual Report on Form 10-K of Georgia Power Company for the year ended December 31, 2016.

/s/Deloitte & Touche LLP

Atlanta, Georgia
February 21, 2017

Exhibit 23(d)1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-211416 on Form S-3 of our reports dated February 21, 2017, relating to the financial statements and financial statement schedule of Gulf Power Company, appearing in this Annual Report on Form 10-K of Gulf Power Company for the year ended December 31, 2016.

/s/Deloitte & Touche LLP

Atlanta, Georgia
February 21, 2017

Exhibit 23(f)1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-213264 on Form S-3 of our report dated February 21, 2017, relating to the consolidated financial statements of Southern Power Company and Subsidiary Companies, appearing in this Annual Report on Form 10-K of Southern Power Company for the year ended December 31, 2016.

/s/Deloitte & Touche LLP

Atlanta, Georgia
February 21, 2017

Exhibit 23(g)1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-212328 on Form S-3 and Registration Statement Nos. 333-26963 and 333-154965 on Form S-8 of our reports dated February 21, 2017, relating to the consolidated financial statements and financial statement schedule of Southern Company Gas and Subsidiary Companies, appearing in this Annual Report on Form 10-K of Southern Company Gas for the year ended December 31, 2016.

/s/Deloitte & Touche LLP

Atlanta, Georgia
February 21, 2017

Exhibit 23(g)2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-212328) and Form S-8 (Nos. 333-26963 and 333-154965) of Southern Company Gas (formerly AGL Resources Inc.) of our report dated February 11, 2016, relating to the financial statements and the financial statement schedule of Southern Company Gas, which appears in this Annual Report on Form 10-K of Southern Company Gas.

/s/ PricewaterhouseCoopers LLP
Atlanta, Georgia
February 21, 2017

Exhibit 23(g)3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-212328) and on Form S-8 (Nos. 333-26963 and 333-154965) of Southern Company Gas of our report dated February 21, 2017 relating to the financial statements of Southern Natural Gas Company, L.L.C., which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Houston, Texas
February 21, 2017

Exhibit 24(a)

February 13, 2017

Myra C. Bierria and Melissa K. Caen

Ms. Bierria and Ms. Caen:

The Southern Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2016 and (2) the Company's Quarterly Reports on Form 10-Q during 2017.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

THE SOUTHERN COMPANY

By /s/Thomas A. Fanning

Thomas A. Fanning
Chairman, President and
Chief Executive Officer

/s/Juanita Powell Baranco
Juanita Powell Baranco

/s/Jon A. Boscia
Jon A. Boscia

/s/Henry A. Clark III
Henry A. Clark III

/s/Thomas A. Fanning
Thomas A. Fanning

/s/David J. Grain
David J. Grain

/s/Veronica M. Hagen
Veronica M. Hagen

/s/Warren A. Hood, Jr.
Warren A. Hood, Jr.

/s/Linda P. Hudson
Linda P. Hudson

/s/Donald M. James
Donald M. James

/s/John D. Johns
John D. Johns

/s/Dale E. Klein
Dale E. Klein

/s/William G. Smith, Jr.
William G. Smith, Jr.

/s/Steven R. Specker
Steven R. Specker

/s/Larry D. Thompson
Larry D. Thompson

/s/E. Jenner Wood III
E. Jenner Wood III

/s/Art P. Beattie
Art P. Beattie

/s/Ann P. Daiss
Ann P. Daiss

Extract from minutes of meeting of the board of directors of The Southern Company.

- - - - - - - - - -

RESOLVED: That for the purpose of signing the reports under the Securities Exchange Act of 1934 to be filed with the Securities and Exchange Commission with respect to the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2016 and its 2017 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its Board of Directors and its officers be and hereby are authorized to give their several powers of attorney to Myra C. Bierria and Melissa K. Caen.

- - - - - - - - - -

The undersigned officer of The Southern Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of The Southern Company, duly held on February 13, 2017, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: February 21, 2017

THE SOUTHERN COMPANY

By /s/Melissa K. Caen

Melissa K. Caen
Corporate Secretary

Exhibit 24(b)

Mark A. Crosswhite
Chairman, President and
Chief Executive Officer

600 North 18th Street
Post Office Box 2641
Birmingham, Alabama 35291-0001

Tel 205.257.1000
Fax 205.257.5100

January 27, 2017

Art P. Beattie
30 Ivan Allen Jr. Blvd., N.W.
Atlanta, Georgia 30308

Melissa K. Caen
30 Ivan Allen Jr. Blvd., N.W.
Atlanta, Georgia 30308

Dear Mr. Beattie and Ms. Caen:

Alabama Power Company (the “Company”) proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company’s Annual Report on Form 10-K for the year ended December 31, 2016 and (2) the Company’s Quarterly Reports on Form 10-Q during 2017.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

ALABAMA POWER COMPANY

By /s/Mark A. Crosswhite
Mark A. Crosswhite
Chairman, President and Chief Executive Officer

/s/Whit Armstrong
Whit Armstrong

/s/Robert D. Powers
Robert D. Powers

/s/David J. Cooper, Sr.
David J. Cooper, Sr.

/s/Catherine J. Randall
Catherine J. Randall

/s/Mark A. Crosswhite
Mark A. Crosswhite

/s/C. Dowd Ritter
C. Dowd Ritter

/s/O. B. Grayson Hall, Jr.
O. B. Grayson Hall, Jr.

/s/R. Mitchell Shackleford III
R. Mitchell Shackleford III

/s/Anthony A. Joseph
Anthony A. Joseph

/s/Philip C. Raymond
Philip C. Raymond

/s/Patricia M. King
Patricia M. King

/s/Anita Allcorn-Walker
Anita Allcorn-Walker

/s/James K. Lowder
James K. Lowder

Extract from minutes of meeting of the board of directors of Alabama Power Company.

- - - - - - - - - -

RESOLVED: That for the purpose of signing the reports under the Securities Exchange Act of 1934 to be filed with the Securities and Exchange Commission with respect to the filing of this Company's Annual Report on Form 10-K for the year ended December 31, 2016 and its 2017 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, this Company, the members of its board of directors and its officers are authorized to give their several powers of attorney to Art P. Beattie and Melissa K. Caen.

- - - - - - - - - -

The undersigned officer of Alabama Power Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Alabama Power Company, duly held on January 27, 2017, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: February 21, 2017

ALABAMA POWER COMPANY

By /s/Melissa K. Caen

Melissa K. Caen
Assistant Secretary

Exhibit 24(c)

February 15, 2017

W. Ron Hinson, David P. Poroch, Art P. Beattie and Melissa K. Caen

Lady and Gentlemen:

Georgia Power Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2016 and (2) the Company's Quarterly Reports on Form 10-Q during 2017.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

GEORGIA POWER COMPANY

By /s/W. Paul Bowers

W. Paul Bowers
Chairman, President and Chief Executive Officer

/s/W. Paul Bowers
W. Paul Bowers

/s/Charles K. Tarbutton
Charles K. Tarbutton

/s/Robert L. Brown, Jr.
Robert L. Brown, Jr.

/s/Beverly Daniel Tatum
Beverly Daniel Tatum

/s/Anna R. Cablik
Anna R. Cablik

/s/Clyde C. Tuggle
Clyde C. Tuggle

/s/Stephen S. Green
Stephen S. Green

/s/Richard W. Ussery
Richard W. Ussery

/s/Douglas J. Hertz
Douglas J. Hertz

/s/W. Ron Hinson
W. Ron Hinson

/s/Kessel D. Stelling, Jr.
Kessel D. Stelling, Jr.

/s/David P. Poroch
David P. Poroch

/s/Jimmy C. Tallent
Jimmy C. Tallent

Extract from minutes of meeting of the board of directors of Georgia Power Company.

- - - - - - - - -

RESOLVED: That for the purpose of signing the reports under the Securities Exchange Act of 1934 to be filed with the Securities and Exchange Commission with respect to the filing of this Company's Annual Report on Form 10-K for the year ended December 31, 2016 and its 2017 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its board of directors and its officers are authorized to give their several powers of attorney to W. Ron Hinson, David P. Poroch, Art P. Beattie and Melissa K. Caen.

- - - - - - - - -

The undersigned officer of Georgia Power Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Georgia Power Company, duly held on February 15, 2017, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: February 21, 2017

GEORGIA POWER COMPANY

By /s/Melissa K. Caen

Melissa K. Caen
Assistant Secretary

Exhibit 24(d)

October 28, 2016

Mr. Art P. Beattie
The Southern Company
30 Ivan Allen Jr. Blvd., NW
Atlanta, GA 30308

Ms. Melissa K. Caen
Southern Company Services, Inc.
30 Ivan Allen Jr. Blvd., NW
Atlanta, GA 30308

Dear Mr. Beattie and Ms. Caen:

Gulf Power Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2016 and (2) the Company's Quarterly Reports on Form 10-Q during 2017.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

GULF POWER COMPANY

By /s/S. W. Connally, Jr.
S. W. Connally, Jr.
Chairman, President and Chief Executive Officer

/s/Allan G. Bense
Allan G. Bense

/s/Deborah H. Calder
Deborah H. Calder

/s/S. W. Connally, Jr.
S. W. Connally, Jr.

/s/William C. Cramer, Jr.
William C. Cramer, Jr.

/s/Julian B. MacQueen
Julian B. MacQueen

/s/J. Mort O'Sullivan, III
J. Mort O'Sullivan, III

/s/Michael T. Rehwinkel
Michael T. Rehwinkel

/s/Winston E. Scott
Winston E. Scott

/s/Xia Liu
Xia Liu

/s/Janet J. Hodnett
Janet J. Hodnett

/s/Susan D. Ritenour
Susan D. Ritenour

Extract from minutes of meeting of the board of directors of Gulf Power Company.

- - - - - - - - - -

RESOLVED, That for the purpose of signing the reports under the Securities Exchange Act of 1934, as amended, to be filed with the Securities and Exchange Commission with respect to the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2016 and its 2017 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its board of directors and its officers are authorized to give their several powers of attorney to Art P. Beattie and Melissa K. Caen.

- - - - - - - - - -

The undersigned officer of Gulf Power Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Gulf Power Company, duly held on October 28, 2016, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: February 21, 2017

GULF POWER COMPANY

By /s/Melissa K. Caen

Melissa K. Caen
Assistant Secretary

Exhibit 24(e)

October 25, 2016

Mr. Art P. Beattie
The Southern Company
30 Ivan Allen Jr. Blvd., NW
Atlanta, GA 30308

Ms. Melissa K. Caen
Southern Company Services, Inc.
30 Ivan Allen Jr. Blvd., NW
Atlanta, GA 30308

Mr. Beattie and Ms. Caen:

Mississippi Power Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2016 and (2) the Company's Quarterly Reports on Form 10-Q during 2017.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

MISSISSIPPI POWER COMPANY

By /s/Anthony L. Wilson

Anthony L. Wilson
Chairman, President and Chief
Executive Officer

/s/Carl J. Chaney
Carl J. Chaney

/s/M. L. Waters
M. L. Waters

/s/L. Royce Cumbest
L. Royce Cumbest

/s/Anthony L. Wilson
Anthony L. Wilson

/s/Thomas A. Dews
Thomas A. Dews

/s/Moses H. Feagin
Moses H. Feagin

/s/Mark E. Keenum
Mark E. Keenum

/s/Cynthia F. Shaw
Cynthia F. Shaw

/s/Christine L. Pickering
Christine L. Pickering

/s/Vicki L. Pierce
Vicki L. Pierce

/s/Philip J. Terrell
Philip J. Terrell

Extract from minutes of meeting of the board of directors of Mississippi Power Company.

- - - - - - - - - -

RESOLVED, That for the purpose of signing the reports under the Securities Exchange Act of 1934, as amended, to be filed with the Securities and Exchange Commission with respect to the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2016 and its 2017 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its board of directors and its officers are authorized to give their several powers of attorney to Art P. Beattie and Melissa K. Caen.

- - - - - - - - - -

The undersigned officer of Mississippi Power Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Mississippi Power Company, duly held on October 25, 2016, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: February 21, 2017

MISSISSIPPI POWER COMPANY

By /s/Melissa K. Caen
Melissa K. Caen
Assistant Secretary

Exhibit 24(f)

November 14, 2016

Mr. Elliott L. Spencer
Southern Power Company
30 Ivan Allen Jr. Blvd, NW
Atlanta, GA 30308

Ms. Melissa K. Caen
Southern Company Services, Inc.
30 Ivan Allen Jr. Blvd, NW
Atlanta, GA 30308

Mr. Spencer and Ms. Caen:

Southern Power Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2016 and (2) the Company's Quarterly Reports on Form 10-Q during 2017.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

SOUTHERN POWER COMPANY

By /s/Joseph A. Miller
Joseph A. Miller
Chairman, President and
Chief Executive Officer

/s/Art P. Beattie
Art P. Beattie

/s/Joseph A. Miller
Joseph A. Miller

/s/Thomas A. Fanning
Thomas A. Fanning

/s/Christopher C. Womack
Christopher C. Womack

/s/Kimberly S. Greene
Kimberly S. Greene

/s/William C. Grantham
William C. Grantham

/s/James Y. Kerr, II
James Y. Kerr, II

/s/Elliott L. Spencer
Elliott L. Spencer

/s/Mark S. Lantrip
Mark S. Lantrip

Extract from minutes of meeting of the board of directors of Southern Power Company.

- - - - - - - - - -

RESOLVED: That for the purpose of signing the reports under the Securities Exchange Act of 1934 to be filed with the Securities and Exchange Commission with respect to the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2016 and its 2017 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its board of directors and its officers are authorized to give their several powers of attorney to Elliott L. Spencer and Melissa K. Caen.

- - - - - - - - - -

The undersigned officer of Southern Power Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Southern Power Company, duly held on November 14, 2016, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: February 21, 2017

SOUTHERN POWER COMPANY

By /s/Melissa K. Caen

Melissa K. Caen
Assistant Secretary

Exhibit 24(g)

February 7, 2017

Myra C. Bierria and Melissa K. Caen

Ms. Bierria and Ms. Caen:

Southern Company Gas (the “Company”) proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company’s Annual Report on Form 10-K for the year ended December 31, 2016 and (2) the Company’s Quarterly Reports on Form 10-Q during 2017.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

SOUTHERN COMPANY GAS

By /s/Andrew W. Evans

Andrew W. Evans
Chairman, President and
Chief Executive Officer

/s/Sandra N. Bane
Sandra N. Bane

/s/Thomas D. Bell, Jr.
Thomas D. Bell, Jr.

/s/Charles R. Crisp
Charles R. Crisp

/s/Andrew W. Evans
Andrew W. Evans

/s/Brenda J. Gaines
Brenda J. Gaines

/s/Kimberly S. Greene
Kimberly S. Greene

/s/John E. Rau
John E. Rau

/s/James A. Rubright
James A. Rubright

/s/Elizabeth W. Reese
Elizabeth W. Reese

/s/Grace A. Kolvereid
Grace A. Kolvereid

Extract from minutes of meeting of the board of directors of Southern Company Gas.

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RESOLVED: That for the purpose of signing the reports under the Securities Exchange Act of 1934 to be filed with the Securities and Exchange Commission with respect to the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2016 and its 2017 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its Board of Directors and its officers be and hereby are authorized to give their several powers of attorney to Myra C. Bierria and Melissa K. Caen.

\- - - - - - - - - -

The undersigned officer of Southern Company Gas does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Southern Company Gas, duly held on February 7, 2017, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: February 21, 2017

SOUTHERN COMPANY GAS

By /s/Melissa K. Caen

Melissa K. Caen
Assistant Secretary

Exhibit 31(a)1

THE SOUTHERN COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Thomas A. Fanning, certify that:

1. I have reviewed this annual report on Form 10-K of The Southern Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2017

/s/Thomas A. Fanning

Thomas A. Fanning

Chairman, President and
Chief Executive Officer

Exhibit 31(a)2

THE SOUTHERN COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Art P. Beattie, certify that:

1. I have reviewed this annual report on Form 10-K of The Southern Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2017

/s/Art P. Beattie

Art P. Beattie

Executive Vice President and Chief Financial Officer

Exhibit 31(b)1

ALABAMA POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Mark A. Crosswhite, certify that:

1. I have reviewed this annual report on Form 10-K of Alabama Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2017

/s/Mark A. Crosswhite

Mark A. Crosswhite
Chairman, President and Chief Executive Officer

Exhibit 31(b)2

ALABAMA POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Philip C. Raymond, certify that:

1. I have reviewed this annual report on Form 10-K of Alabama Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2017

/s/Philip C. Raymond

Philip C. Raymond
Executive Vice President, Chief Financial Officer
and Treasurer

Exhibit 31(c)1

GEORGIA POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, W. Paul Bowers, certify that:

1. I have reviewed this annual report on Form 10-K of Georgia Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2017

/s/W. Paul Bowers

W. Paul Bowers

Chairman, President and Chief Executive Officer

Exhibit 31(c)2

GEORGIA POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, W. Ron Hinson, certify that:

1. I have reviewed this annual report on Form 10-K of Georgia Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2017

/s/W. Ron Hinson

W. Ron Hinson

Executive Vice President, Chief Financial Officer and Treasurer

Exhibit 31(d)1

GULF POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, S. W. Connally, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Gulf Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2017

/s/S. W. Connally, Jr.

S. W. Connally, Jr.
Chairman, President and Chief Executive Officer

Exhibit 31(d)2

GULF POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Xia Liu, certify that:

1. I have reviewed this annual report on Form 10-K of Gulf Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2017

/s/Xia Liu

Xia Liu

Vice President and Chief Financial Officer

Exhibit 31(e)1

MISSISSIPPI POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Anthony L. Wilson, certify that:

1. I have reviewed this annual report on Form 10-K of Mississippi Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2017

/s/Anthony L. Wilson

Anthony L. Wilson

Chairman, President and
Chief Executive Officer

Exhibit 31(e)2

MISSISSIPPI POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Moses H. Feagin, certify that:

1. I have reviewed this annual report on Form 10-K of Mississippi Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2017

/s/Moses H. Feagin

Moses H. Feagin

Vice President, Treasurer and
Chief Financial Officer

Exhibit 31(f)1

SOUTHERN POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Joseph A. Miller, certify that:

1. I have reviewed this annual report on Form 10-K of Southern Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2017

/s/Joseph A. Miller

Joseph A. Miller

Chairman, President and Chief Executive Officer

Exhibit 31(f)2

SOUTHERN POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, William C. Grantham, certify that:

1. I have reviewed this annual report on Form 10-K of Southern Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2017

/s/William C. Grantham

William C. Grantham

Senior Vice President, Treasurer and Chief
Financial Officer

Exhibit 31(g)1

SOUTHERN COMPANY GAS

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Andrew W. Evans, certify that:

1. I have reviewed this annual report on Form 10-K of Southern Company Gas;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2017

/s/Andrew W. Evans

Andrew W. Evans

Chairman, President and Chief Executive Officer

Exhibit 31(g)2

SOUTHERN COMPANY GAS

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Elizabeth W. Reese, certify that:

1. I have reviewed this annual report on Form 10-K of Southern Company Gas;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2017

/s/Elizabeth W. Reese

Elizabeth W. Reese

Executive Vice President and
Chief Financial Officer

Exhibit 32(a)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report on Form 10-K of The Southern Company for the year ended December 31, 2016, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of The Southern Company for the year ended December 31, 2016, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of The Southern Company for the year ended December 31, 2016, fairly presents, in all material respects, the financial condition and results of operations of The Southern Company.

/s/Thomas A. Fanning

Thomas A. Fanning
Chairman, President and
Chief Executive Officer

/s/Art P. Beattie

Art P. Beattie
Executive Vice President and
Chief Financial Officer

February 21, 2017

Exhibit 32(b)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report on Form 10-K of Alabama Power Company for the year ended December 31, 2016, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Alabama Power Company for the year ended December 31, 2016, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Alabama Power Company for the year ended December 31, 2016, fairly presents, in all material respects, the financial condition and results of operations of Alabama Power Company.

/s/Mark A. Crosswhite
Mark A. Crosswhite
Chairman, President and Chief Executive Officer

/s/Philip C. Raymond
Philip C. Raymond
Executive Vice President,
Chief Financial Officer and Treasurer

February 21, 2017

Exhibit 32(c)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report on Form 10-K of Georgia Power Company for the year ended December 31, 2016, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Georgia Power Company for the year ended December 31, 2016, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Georgia Power Company for the year ended December 31, 2016, fairly presents, in all material respects, the financial condition and results of operations of Georgia Power Company.

/s/W. Paul Bowers
W. Paul Bowers
Chairman, President and Chief Executive Officer

/s/W. Ron Hinson
W. Ron Hinson
Executive Vice President, Chief Financial Officer and Treasurer

February 21, 2017

Exhibit 32(d)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report on Form 10-K of Gulf Power Company for the year ended December 31, 2016, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Gulf Power Company for the year ended December 31, 2016, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Gulf Power Company for the year ended December 31, 2016, fairly presents, in all material respects, the financial condition and results of operations of Gulf Power Company.

/s/S. W. Connally, Jr.
S. W. Connally, Jr.
Chairman, President and Chief Executive Officer

/s/Xia Liu
Xia Liu
Vice President and Chief Financial Officer

February 21, 2017

Exhibit 32(e)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report on Form 10-K of Mississippi Power Company for the year ended December 31, 2016, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Mississippi Power Company for the year ended December 31, 2016, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Mississippi Power Company for the year ended December 31, 2016, fairly presents, in all material respects, the financial condition and results of operations of Mississippi Power Company.

/s/Anthony L. Wilson

Anthony L. Wilson
Chairman, President and Chief Executive Officer

/s/Moses H. Feagin

Moses H. Feagin
Vice President, Treasurer and
Chief Financial Officer

February 21, 2017

Exhibit 32(f)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report on Form 10-K of Southern Power Company for the year ended December 31, 2016, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Southern Power Company for the year ended December 31, 2016, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Southern Power Company for the year ended December 31, 2016, fairly presents, in all material respects, the financial condition and results of operations of Southern Power Company.

/s/Joseph A. Miller
Joseph A. Miller
Chairman, President and Chief Executive Officer

/s/William C. Grantham
William C. Grantham
Senior Vice President, Treasurer and
Chief Financial Officer

February 21, 2017

Exhibit 32(g)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report on Form 10-K of Southern Company Gas for the year ended December 31, 2016, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Southern Company Gas for the year ended December 31, 2016, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Southern Company Gas Company for the year ended December 31, 2016, fairly presents, in all material respects, the financial condition and results of operations of Southern Company Gas.

/s/Andrew W. Evans

Andrew W. Evans
Chairman, President and Chief Executive Officer

/s/Elizabeth W. Reese

Elizabeth W. Reese
Executive Vice President and
Chief Financial Officer

February 21, 2017

Exhibit 99(g)

CONSOLIDATED FINANCIAL STATEMENTS
With Report of Independent Registered Public Accounting Firm

SOUTHERN NATURAL GAS COMPANY, L.L.C.

As of December 31, 2016 and
For the Four Months Ended December 31, 2016

SOUTHERN NATURAL GAS COMPANY, L.L.C. AND SUBSIDIARY
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Report of Independent Registered Public Accounting Firm

To the Members and Management of Southern Natural Gas Company, L.L.C.:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of income, members' equity and cash flows present fairly, in all material respects, the financial position of Southern Natural Gas Company, L.L.C. and its subsidiary (the "Company") as of December 31, 2016 and the results of its operations and its cash flows for the period from September 1, 2016 through December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States) and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

Emphasis of Matter

As discussed in Note 6 to the consolidated financial statements, the Company had extensive operations and relationships with affiliated entities. Our opinion is not modified with respect to this matter.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 21, 2017

SOUTHERN NATURAL GAS COMPANY, L.L.C. AND SUBSIDIARY
CONSOLIDATED STATEMENT OF INCOME
(In Millions)

	Four Months Ended December 31, 2016
Revenues	$ 230
Operating Costs and Expenses	
Operations and maintenance	39
Depreciation and amortization	27
General and administrative	13
Taxes, other than income taxes	13
Total Operating Costs and Expenses	92
Operating Income	138
Other Income (Expense)	
Earnings from equity investment	2
Interest, net	(26)
Other, net	1
Total Other Income (Expense)	(23)
Net Income	$ 115

The accompanying notes are an integral part of this consolidated financial statement.

SOUTHERN NATURAL GAS COMPANY, L.L.C. AND SUBSIDIARY
CONSOLIDATED BALANCE SHEET
(In Millions)

		December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$	4
Accounts receivable, net		65
Inventories		19
Regulatory assets		4
Other current assets		3
Total current assets		95
Property, plant and equipment, net		2,451
Investment		61
Regulatory assets		36
Deferred charges and other assets		32
Total Assets	$	2,675
LIABILITIES AND MEMBERS' EQUITY		
Current liabilities		
Current portion of debt	$	500
Accounts payable		34
Accrued interest		19
Accrued taxes, other than income taxes		22
Other current liabilities		13
Total current liabilities		588
Long-term liabilities and deferred credits		
Long-term debt, net of debt issuance costs		706
Other long-term liabilities and deferred credits		22
Total long-term liabilities and deferred credits		728
Total Liabilities		1,316
Commitments and contingencies (Note 9)		
Members' Equity		1,359
Total Liabilities and Members' Equity	$	2,675

The accompanying notes are an integral part of this consolidated financial statement.

SOUTHERN NATURAL GAS COMPANY, L.L.C. AND SUBSIDIARY
CONSOLIDATED STATEMENT OF CASH FLOWS
(In Millions)

	Four Months Ended December 31, 2016
Cash Flows From Operating Activities	
Net income	$ 115
Adjustments to reconcile net income to net cash provided by operating activities:	
Depreciation and amortization	27
Earnings from equity investment	(2)
Other non-cash items	1
Distributions from equity investment earnings	3
Changes in components of working capital:	
Accounts receivable	(7)
Regulatory assets	5
Accounts payable	10
Accrued taxes, other than income taxes	(4)
Accrued interest	(7)
Other current assets and liabilities	1
Other long-term assets and liabilities	(1)
Net Cash Provided by Operating Activities	141
Cash Flows From Investing Activities	
Capital expenditures	(33)
Net Cash Used in Investing Activities	(33)
Cash Flows From Financing Activities	
Issuance of debt	56
Payment of debt	(56)
Contributions from Members	15
Distributions to Members	(119)
Net Cash Used in Financing Activities	(104)
Net Increase in Cash and Cash Equivalents	4
Cash and Cash Equivalents, beginning of period	—
Cash and Cash Equivalents, end of period	$ 4
Supplemental Disclosure of Cash Flow Information	
Cash paid during the period for interest (net of capitalized interest)	$ 24

The accompanying notes are an integral part of this consolidated financial statement.

SOUTHERN NATURAL GAS COMPANY, L.L.C. AND SUBSIDIARY
CONSOLIDATED STATEMENT OF MEMBERS' EQUITY
(In Millions)

	Four Months Ended December 31, 2016
Beginning Balance	$ 1,348
Net income	115
Contributions	15
Distributions	(119)
Ending Balance	$ 1,359

The accompanying notes are an integral part of this consolidated financial statement.

SOUTHERN NATURAL GAS COMPANY, L.L.C. AND SUBSIDIARY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. General

We are a Delaware limited liability company, originally formed in 1935 as a corporation. When we refer to "us," "we," "our," "ours," "the Company," or "SNG," we are describing Southern Natural Gas Company, L.L.C and its consolidated subsidiary.

Kinder Morgan, Inc. (KMI) Sale of Equity Interest to The Southern Company (TSC)

Prior to September 2016, we were an indirect wholly owned subsidiary of KMI. On September 1, 2016, KMI completed the sale of a 50% interest in SNG to TSC. We continue to be operated by KMI.

The resulting member interests in SNG are as follows:

- 50.0% - Kinder Morgan SNG Operator, LLC, an indirect subsidiary of KMI; and
- 50.0% - Evergreen Enterprise Holdings, LLC, a subsidiary of Southern Company Gas, a subsidiary of TSC.

Our operations are regulated by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005. The FERC approves tariffs that establish rates, cost recovery mechanisms and other terms and conditions of service to our customers.

Our primary business consists of the interstate transportation and storage of natural gas. Our natural gas pipeline system consists of approximately 6,900 miles of pipeline with a design capacity of approximately 4.1 billion cubic feet (Bcf) per day for natural gas. This pipeline system extends from supply basins in Louisiana, Mississippi and Alabama to market areas in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee, including the metropolitan areas of Atlanta and Birmingham. We also own and operate 100% of the Muldon storage facility in Monroe County, Mississippi and own a 50% interest in Bear Creek Storage Company, L.L.C. (Bear Creek) in Bienville Parish, Louisiana. Bear Creek is a joint venture equally owned by us and Tennessee Gas Pipeline Company, L.L.C., an affiliate. Our interest in Bear Creek, the Muldon storage facilities and contracted storage have a combined working natural gas storage capacity of approximately 68 Bcf and peak withdrawal capacity of approximately 1.3 Bcf per day.

2. Summary of Significant Accounting Policies

Basis of Presentation

We have prepared our accompanying consolidated financial statements in accordance with the accounting principles contained in the Financial Accounting Standards Board's (FASB) Accounting Standards Codification, the single source of United States Generally Accepted Accounting Principles (GAAP) and referred to in this report as the Codification.

Management has evaluated subsequent events through February 21, 2017, the date the financial statements were available to be issued.

Principles of Consolidation

We consolidate entities when we have the ability to control or direct the operating and financial decisions of the entity or when we have a significant interest in the entity that gives us the ability to direct the activities that are significant to that entity. The determination of our ability to control, direct or exert significant influence over an entity involves the use of judgment. All significant intercompany items have been eliminated in consolidation.

Use of Estimates

Certain amounts included in or affecting our financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions which cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for assets and liabilities, our revenues and expenses during the reporting period, and our disclosures, including as it relates to contingent assets and liabilities at the date of our financial statements. We evaluate these estimates on an ongoing basis, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

In addition, we believe that certain accounting policies are of more significance in our financial statement preparation process than others, and set out below are the principal accounting policies we apply in the preparation of our consolidated financial statements.

Cash Equivalents

We define cash equivalents as all highly liquid short-term investments with original maturities of three months or less.

Accounts Receivable, net

We establish provisions for losses on accounts receivable due from shippers and operators if we determine that we will not collect all or part of the outstanding balance. We regularly review collectability and establish or adjust our allowance as necessary using the specific identification method. The allowance for doubtful accounts as of December 31, 2016 was not significant.

Inventories

Our inventories, which consist of materials and supplies, are valued at weighted-average cost, and we periodically review for physical deterioration and obsolescence.

Natural Gas Imbalances

Natural gas imbalances occur when the amount of natural gas delivered from or received by a pipeline system or storage facility differs from the scheduled amount of gas to be delivered or received. We value these imbalances due to or from shippers and operators at current index prices. Imbalances are settled in cash or made up in-kind, subject to the terms of our FERC tariff. Imbalances due from others are reported on our accompanying Consolidated Balance Sheet in “Other current assets.” Imbalances owed to others are reported on our accompanying Consolidated Balance Sheet in “Other current liabilities.” We classify all imbalances due from or owed to others as current as we expect to settle them within a year.

Property, Plant and Equipment, net

Our property, plant and equipment is recorded at its original cost of construction or, upon acquisition, at either the fair value of the assets acquired or the cost to the entity that first placed the asset in utility service. For constructed assets, we capitalize all construction-related direct labor and material costs, as well as indirect construction costs. Our indirect construction costs primarily include an interest and equity return component (as more fully described below) and labor and related costs associated with supporting construction activities. The indirect capitalized labor and related costs are based upon estimates of time spent supporting construction projects.

We use the composite method to depreciate property, plant and equipment. Under this method, assets with similar economic characteristics are grouped and depreciated as one asset. The FERC-accepted depreciation rate is applied to the total

cost of the group until the net book value equals the salvage value. For certain general plant, the asset is depreciated to zero. As part of periodic filings with the FERC, we also re-evaluate and receive approval for our depreciation rates. When property, plant and equipment is retired, accumulated depreciation and amortization is charged for the original cost of the assets in addition to the cost to remove, sell or dispose of the assets, less salvage value. We do not recognize gains or losses unless we sell land or sell or retire an entire operating unit (as approved by the FERC). In those instances where we receive recovery in rates related to losses on dispositions of operating units, we record a regulatory asset for the estimated recoverable amount.

Included in our property balances are base gas and working gas at our storage facilities. We periodically evaluate natural gas volumes at our storage facilities for gas losses. When events or circumstances indicate a loss has occurred, we recognize a loss on our accompanying Consolidated Statements of Income or defer the loss as a regulatory asset on our accompanying Consolidated Balance Sheet if deemed probable of recovery through future rates charged to customers.

We capitalize a carrying cost (an allowance for funds used during construction or AFUDC) on debt and equity funds related to the construction of long-lived assets. This carrying cost consists of a return on the investment financed by debt and a return on the investment financed by equity. The debt portion is calculated based on our average cost of debt. Interest costs capitalized are included as a reduction in "Interest, net" on our accompanying Consolidated Statement of Income. The equity portion is calculated based on our most recent FERC approved rate of return. Equity amounts capitalized are included in "Other, net" on our accompanying Consolidated Statement of Income. The amounts of capitalized AFUDC were not significant for the four months ended December 31, 2016.

Asset Retirement Obligations (ARO)

We record liabilities for obligations related to the retirement and removal of long-lived assets used in our businesses. We record, as liabilities, the fair value of ARO on a discounted basis when they are incurred and can be reasonably estimated, which is typically at the time the assets are installed or acquired. Amounts recorded for the related assets are increased by the amount of these obligations. Over time, the liabilities increase due to the change in their present value, and the initial capitalized costs are depreciated over the useful lives of the related assets. The liabilities are eventually extinguished when the asset is taken out of service.

We are required to operate and maintain our natural gas pipelines and storage systems, and intend to do so as long as supply and demand for natural gas exists, which we expect for the foreseeable future. Therefore, we believe that we cannot reasonably estimate the ARO for the substantial majority of our assets because these assets have indeterminate lives. We continue to evaluate our ARO and future developments could impact the amounts we record. Our recorded ARO was not significant as of December 31, 2016.

Asset and Investment Impairments

We evaluate our assets and investments for impairment when events or circumstances indicate that their carrying values may not be recovered. These events include market declines that are believed to be other than temporary, changes in the manner in which we intend to use a long-lived asset, decisions to sell an asset or investment and adverse changes in market conditions or in the legal or business environment such as adverse actions by regulators. If an event occurs, which is a determination that involves judgment, we evaluate the recoverability of our carrying value based on either (i) the long-lived asset's ability to generate future cash flows on an undiscounted basis or (ii) the fair value of the investment in an unconsolidated affiliate. If an impairment is indicated, or if we decide to sell a long-lived asset or group of assets, we adjust the carrying value of the asset downward, if necessary, to its estimated fair value.

Our fair value estimates are generally based on assumptions market participants would use, including market data obtained through the sales process or an analysis of expected discounted future cash flows. There was no impairment for the four months ended December 31, 2016.

Equity Method of Accounting

We account for investments, which we do not control but do have the ability to exercise significant influence, by the equity method of accounting. Under this method, our equity investments are carried originally at our acquisition cost, increased by our proportionate share of the investee's net income and by contributions made, and decreased by our proportionate share of the investee's net losses and by distributions received.

Revenue Recognition

We are subject to FERC regulations, therefore fees and rates established under our tariff are a function of our cost of providing services to our customers, including a reasonable return on our invested capital. Our revenues are primarily generated from natural gas transportation and storage services and include estimates of amounts earned but unbilled. We estimate these unbilled revenues based on contract data, regulatory information, and preliminary throughput and allocation measurements, among other items. Revenues for all services are based on the thermal quantity of gas delivered or subscribed at a price specified in the contract. For our transportation services and storage services, we recognize reservation revenues on firm contracted capacity ratably over the contract period regardless of the amount of natural gas that is transported or stored. For interruptible or volumetric-based services, we record revenues when physical deliveries of natural gas are made at the agreed upon delivery point or when gas is injected or withdrawn from the storage facility. For contracts with step-up or step-down rate provisions that are not related to changes in levels of service, we recognize reservation revenues ratably over the contract life. The revenues we collect may be subject to refund in a rate proceeding. We had no reserves for potential rate refunds as of December 31, 2016.

For the four months ended December 31, 2016, revenues from our largest affiliate and non-affiliate customers were approximately $89 million and $52 million (includes contracted capacity released by customer to third parties), respectively, each of which exceeded 10% of our operating revenues for that period (see Note 6).

In September 2016, we recognized revenue of $37 million from an early termination of a customer contract.

Environmental Matters

We capitalize or expense, as appropriate, environmental expenditures. We capitalize certain environmental expenditures required in obtaining rights-of-way, regulatory approvals or permitting as part of the construction. We accrue and expense environmental costs that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation. We generally do not discount environmental liabilities to a net present value, and we record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, our recording of these accruals coincides with our completion of a feasibility study or our commitment to a formal plan of action. We recognize receivables for anticipated associated insurance recoveries when such recoveries are deemed to be probable.

We routinely conduct reviews of potential environmental issues and claims that could impact our assets or operations. These reviews assist us in identifying environmental issues and estimating the costs and timing of remediation efforts. We also routinely adjust our environmental liabilities to reflect changes in previous estimates. In making environmental liability estimations, we consider the material effect of environmental compliance, pending legal actions against us, and potential third-party liability claims. Often, as the remediation evaluation and effort progresses, additional information is obtained, requiring revisions to estimated costs. These revisions are reflected in our income in the period in which they are reasonably determinable. For more information on our environmental matters, see Note 9.

Other Contingencies

We recognize liabilities for other contingencies when we have an exposure that indicates it is both probable that a liability has been incurred and the amount of loss can be reasonably estimated. Where the most likely outcome of a contingency can be reasonably estimated, we accrue an undiscounted liability for that amount. Where the most likely outcome cannot be estimated, a range of potential losses is established and if no one amount in that range is more likely than any other, the low end of the range is accrued.

Postretirement Benefits

We maintain a postretirement benefit plan covering certain of our former employees that we have made contributions to in the past. These contributions are invested until the benefits are paid to plan participants. The net benefit cost of this plan is recorded on our accompanying Consolidated Statements of Income and is a function of many factors including expected returns on plan assets and amortization of certain deferred gains and losses. For more information on our policies with respect to our postretirement benefit plan, see Note 5.

In accounting for our postretirement benefit plan, we record an asset or liability based on the difference between the fair value of the plan's assets and the plan's benefit obligation. Any deferred amounts related to unrecognized gains and losses or changes in actuarial assumptions are recorded on our Consolidated Balance Sheet as a regulatory asset or liability until those gains or losses are recognized on our accompanying Consolidated Statement of Income.

Income Taxes

We are a limited liability company and are not subject to federal income taxes or state income taxes. Our members are responsible for income taxes on their allocated share of taxable income which may differ from income for financial statement purposes due to differences in the tax basis and financial reporting basis of assets and liabilities. However, we are subject to Texas margin tax (a revenue based calculation).

Regulatory Assets and Liabilities

Our interstate natural gas pipeline and storage operations are subject to the jurisdiction of the FERC and are accounted for in accordance with Accounting Standards Codification Topic 980, “Regulated Operations.” Under these standards, we record regulatory assets and liabilities that would not be recorded for non-regulated entities. Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges and credits that are expected to be recovered from or refunded to customers through the rate making process. Items to which we apply regulatory accounting requirements include certain postretirement employee benefit plan costs, losses on reacquired debt, taxes related to an equity return component on regulated capital projects prior to our change in legal structure to a non taxable entity, certain differences between gas retained and gas consumed in operations and other costs included in, or expected to be included in, future rates. For more information on our regulated operations, see Note 8.

3. Property, Plant and Equipment, net

Our property, plant and equipment, net consisted of the following (in millions, except for %):

	Annual Depreciation Rates %	December 31, 2016
Transmission and storage facilities	0.9-2.25	$ 3,570
General plant	3.33-20	25
Intangible plant	5-10	19
Other		116
Accumulated depreciation and amortization (a)		(1,344)
		2,386
Land		12
Construction work in progress		53
Property, plant and equipment, net		$ 2,451

(a) The composite weighted average depreciation rate for the four months ended December 31, 2016 was approximately 2.3%.

4. Debt

We classify our debt based on the contractual maturity dates of the underlying debt instruments. We defer costs associated with debt issuance over the applicable term. These costs are then amortized as interest expense on our accompanying Consolidated Statement of Income.

The following table summarizes the net carrying value of our outstanding debt (in millions):

	December 31, 2016
5.90% Notes due April 2017(a)	$ 500
4.40% Notes due June 2021	300
7.35% Notes due February 2031	153
8.00% Notes due March 2032	258
	1,211
Less: Unamortized discount and debt issuance costs	5
Total debt	$ 1,206
Less: Current portion of debt(a)	500
Total long-term debt	$ 706

(a) As of December 31, 2016, we included $500 million of our 5.90% Notes due April 2017 within the caption “Current portion of debt” on our accompanying Consolidated Balance Sheet. We intend to satisfy this debt through the issuance of bank or bond debt, issuance of notes to our Members, equity contributions from our Members, or a combination of these options.

Credit Facility

Effective September 1, 2016, we entered into a $75 million, unsecured, 5-year revolving credit facility (Credit Facility). The facility is with a syndicate of financial institutions with Barclays Bank PLC as the administrative agent. Borrowings under our Credit Facility can be used for working capital and other general corporate purposes.

Our Credit Facility borrowings bear interest at either (i) London Interbank Offered Rate (LIBOR) plus an applicable margin ranging from 0.875% to 1.50% per annum based on our credit ratings or (ii) the greatest of the (a) Federal Funds Effective rate plus ½ of 1%, (b) the Prime Rate in effect for such day, and (c) the LIBOR rate for a one-month Eurodollar loan

plus 1%, plus, in each case, an applicable margin ranging from nil to 1.5%. In addition, we have agreed to pay the administrative agent a commitment fee, based on our credit rating, ranging from 0.075% to 0.200%. As of December 31, 2016, we were in compliance with all required financial covenants.

Our Credit Facility includes the following restrictive covenants:

- total debt divided by earnings before interest, income taxes, depreciation and amortization may not exceed 5.00 to 1.00;
- certain limitations on indebtedness, including payments and amendments;
- certain limitations on entering into mergers, consolidations, sales of assets and investments;
- limitations on granting liens; and
- prohibitions on making any distributions if an event of default exists or would exist upon making such a distribution.

As of December 31, 2016 we had no borrowings outstanding under our Credit Facility.

Debt Covenants

Under our various other financing documents, we are subject to certain restrictions and covenants. The most restrictive of these include limitations on the incurrence of liens and limitations on sale-leaseback transactions. For the four months ended December 31, 2016, we were in compliance with our debt-related covenants.

5. Retirement Benefits

Pension and Retirement Savings Plans

KMI maintains a pension plan and a retirement savings plan covering substantially all of its U.S. employees, including certain of our former employees. The benefits under the pension plan are determined under a cash balance formula. Under its retirement savings plan, KMI contributes an amount equal to 5% of participants’ eligible compensation per year. KMI is responsible for benefits accrued under its plans and allocates certain costs based on a benefit allocation rate applied on payroll charged to its affiliates.

Postretirement Benefits Plan

We provide postretirement benefits, including medical benefits for a closed group of retirees. Medical benefits for this closed group may be subject to deductibles, co-payment provisions, dollar caps and other limitations on the amount of employer costs, and are subject to further benefit changes by KMI, the plan sponsor. Effective January 1, 2014, the plan was amended to provide a fixed subsidy to post-age 65 Medicare eligible participants to purchase coverage through a retiree Medicare exchange. In addition, certain employees continue to receive limited postretirement life insurance benefits. Our postretirement benefit plan costs were prefunded and were recoverable under prior rate case settlements. Currently, there is no cost recovery or related funding that is required as part of our current FERC approved rates, however, we can seek to recover any funding shortfall that may be required in the future. We do not expect to make any contributions to our postretirement benefit plan in 2017 and there were no contributions made in 2016. KMI's postretirement plans have been merged. KMI is permitted to use combined plan assets under the structure of the plans of its affiliated entities to fund participant benefits, including participants of affiliated entities.

Postretirement Benefit Obligation, Plan Assets and Funded Status

Our postretirement benefit obligations and net benefit costs are primarily based on actuarial calculations. We use various assumptions in performing these calculations, including those related to the return that we expect to earn on our plan assets, the estimated cost of health care when benefits are provided under our plan and other factors. A significant assumption we utilize is the discount rates used in calculating the benefit obligations. The discount rate used in the measurement of our postretirement obligation is determined

by matching the timing and amount of our expected future benefit payments to the average yields of various high-quality bonds with corresponding maturities.

We estimate the service and interest cost components of net periodic benefit cost (credit) for our other postretirement benefit plan with a full yield curve approach by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to their underlying projected cash flows. The estimate provides a more precise measurement of service and interest costs by improving the correlation between projected benefit cash flows and their corresponding spot rates.

The table below provides information about our postretirement benefit plan as of and for the four months ended December 31, 2016 (in millions):

		2016
Change in postretirement benefit obligation:		
Postretirement benefit obligation - beginning of period	$	30
Interest cost(a)		—
Actuarial gain(a)		—
Benefits paid		(1)
Postretirement benefit obligation - end of period	$	29
Change in plan assets:		
Fair value of plan assets - beginning of period	$	57
Actual return on plan assets		2
Employer contributions/transfers		—
Benefits paid		(1)
Fair value of plan assets - end of period	$	58
Reconciliation of funded status:		
Fair value of plan assets	$	58
Less: Postretirement benefit obligation		29
Net asset at December 31(b)	$	29

(a) Amounts during the four months ended December 31, 2016 were less than $500,000.
(b) Net asset amounts are included in “Deferred charges and other assets” on our accompanying Consolidated Balance Sheet.

Plan Assets

The primary investment objective of our plan is to ensure that, over the long-term life of the plan, an adequate pool of sufficiently liquid assets exists to meet the benefit obligations to retirees and beneficiaries. Investment objectives are long-term in nature covering typical market cycles. Any shortfall of investment performance compared to investment objectives is generally the result of economic and capital market conditions. Although actual allocations vary from time to time from our targeted allocations, the target allocations of our postretirement plan’s assets are 30% equity, 30% fixed income and 40% master limited partnerships.

Below are the details of the postretirement benefit plan assets by class and a description of the valuation methodologies used for assets measured at fair value.

- Level 1 assets' fair values are based on quoted market prices for the instruments in actively traded markets. Included in this are equities and master limited partnerships using the quoted prices in actively traded markets;
- Level 2 assets' fair values are primarily based on pricing, data representative of quoted prices for similar assets in active markets (or identical assets in less active markets). Included in this are short term investment funds which are valued at cost plus calculated interest; and
- Plan assets with fair values that are based on the net asset value per share, or its equivalent (NAV), as reported by the issuers are determined based on the fair value of the underlying securities as of the valuation date and include private

limited partnerships and fixed income trusts. These amounts are not categorized within the fair value hierarchy described above, but are separately identified in the following tables.

Listed below are the fair values of the plan's assets that are recorded at fair value by class and categorized by fair value measurement used at December 31, 2016 (in millions):

	Level 1	Level 2	Total
Short-term investment fund (money market)	$ —	$ 1	$ 1
Equity securities, domestic	3	—	3
Master limited partnerships	14	—	14
Total assets in fair value hierarchy	$ 17	$ 1	$ 18
Investments measured at NAV(a)			40
Investments at fair value			$ 58

(a) In accordance with Subtopic 820-10 of Accounting Standards Update (ASU) No. 2015-07, *Fair Value Measurement (Topic 820)* , certain Plan assets that were measured at NAV per share (or its equivalent) have not been classified in the fair value hierarchy. The fair value of the fixed income trusts as of December 31, 2016 is $15 million. The fair value of the private limited partnerships as of December 31, 2016 is $25 million.

Expected Payment of Future Benefits

As of December 31, 2016, we expect the following benefit payments under our plan (in millions):

Year	Total
2017	$ 3
2018	3
2019	3
2020	3
2021	2
2022 - 2026	10

Actuarial Assumptions and Sensitivity Analysis

Postretirement benefit obligations and net benefit costs are based on actuarial estimates and assumptions. The following table details the weighted average actuarial assumptions used in determining our postretirement plan obligations and net benefit costs.

	2016 (%)
Assumptions related to benefit obligations at December 31:	
Discount rate	3.63
Assumptions related to benefit costs for the year ended December 31:	
Discount rate for benefit obligations	3.82
Discount rate for interest on benefit obligations	2.98
Expected return on plan assets(a)	7.25

(a) The expected return on plan assets listed in the table above is a pre-tax rate of return based on our portfolio of investments. We utilize an after-tax expected return on plan assets to determine our benefit costs, which is based on unrelated business income taxes with a weighted average rate of 21% for 2016.

Actuarial estimates for our postretirement benefits plan assumed a weighted average annual rate of increase in the per capita costs of covered health care benefits of 7.2%, gradually decreasing to 4.5% by the year 2038. A one-percentage point change in assumed health care trends would not have had a significant effect on the postretirement benefit obligation or interest costs as of and for the four months ended December 31, 2016.

Components of Net Benefit Income

The components of net benefit costs (income) are as follows (in millions):

	Four Months Ended December 31, 2016
Interest cost(a)	$ —
Expected return on plan assets	(1)
Amortization of prior service credit(a)	—
Net benefit income	$ (1)

(a) Amounts during the four months ended December 31, 2016 were less than $500,000.

6. Related Party Transactions

Affiliate Balances and Activities

We enter into transactions with our affiliates within the ordinary course of business and the services are based on the same terms as non-affiliates, including natural gas transportation services to and from affiliates under long-term contracts, storage contracts and various operating agreements.

We do not have employees and are operated by an indirect subsidiary of KMI; therefore, KMI employees provide services to us. Subsequent to TSC's acquisition, we entered into an Operations and Management (O&M Agreement) with Kinder Morgan SNG Operator, LLC, a subsidiary of KMI whereby we reimburse KMI monthly for direct operating expenses incurred on our behalf and pay a fixed annual fee for general and administrative costs. The fixed fee for the four months ended December 31, 2016 was $13 million. The fixed fee will be $30 million for the year 2017 and $31 million for each of the years 2018 through 2020, and is subject to review and approval for each of the next four years pursuant to the O&M Agreement. These costs are reflected, as appropriate, in the "Operations and maintenance", "General and administrative" and "Capitalized costs" lines in the table below.

The following table summarizes our other balance sheet affiliate balances (in millions):

	December 31, 2016
Accounts receivable	$ 18
Natural gas imbalance receivable(a)	1
Accounts payable	9

(a) Included in “Other current assets” on our accompanying Consolidated Balance Sheet.

The following table shows revenues and costs from our affiliates (in millions):

		Four Months Ended December 31, 2016
Revenues	$	67
Operations and maintenance		24
General and administrative		13
Capitalized costs		4

Subsequent Event

In January 2017, we made a cash distribution to our Members of $20 million and received contributions from our Members of $3 million.

7. Fair Value

The following table reflects the carrying amount and estimated fair value of our outstanding debt balance (in millions):

	As of December 31, 2016		
	Carrying Amount		Estimated Fair Value
Total debt	$	1,206	$1,312

We separate the fair values of our financial instruments into levels based on our assessment of the availability of observable market data and the significance of non-observable data used to determine the estimated fair value. We estimated the fair values of our outstanding debt balance primarily based on quoted market prices for the same or similar issues, a Level 2 fair value measurement. Our assessment and classification of an instrument within a level can change over time based on the maturity or liquidity of the instrument and this change would be reflected at the end of the period in which the change occurs. During the four months ended December 31, 2016, there were no changes to the inputs and valuation techniques used to measure fair value, the types of instruments, or the levels in which they were classified.

8. Accounting for Regulatory Activities

Regulatory Assets and Liabilities

Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges and credits that will be recovered from or refunded to customers through the ratemaking process. As of December 31, 2016, the regulatory assets are being recovered in our rates, without earning a return, over a period of approximately one year to 27 years. Below are the details of our regulatory assets and liabilities as of (in millions):

	December 31, 2016
Current regulatory assets	
Difference between gas retained and gas consumed in operations	$ 3
Other	1
Total current regulatory assets	4
Non-current regulatory assets	
Taxes on capitalized funds used during construction	24
Unamortized loss on reacquired debt	10
Other	2
Total non-current regulatory assets	36
Total regulatory assets	$ 40
Current regulatory liabilities	
Difference between gas retained and gas consumed in operations	$ 1
Other	2
Total current regulatory liabilities (a)	3
Non-current regulatory liabilities	
Postretirement benefits	19
Other	2
Total non-current regulatory liabilities (b)	21
Total regulatory liabilities	$ 24

(a) Included in “Other current liabilities” on our accompanying Consolidated Balance Sheet.
(b) Included in “Other long-term liabilities and deferred credits” on our accompanying Consolidated Balance Sheet.

Our significant regulatory assets and liabilities include:

Difference between gas retained and gas consumed in operations

Amounts reflect the value of the difference between the gas retained and consumed in our operations. Pursuant to our tariff, these amounts are expected to be recovered from our customers in subsequent periods.

Taxes on capitalized funds used during construction

Amounts represent the recovery of deferred income taxes on AFUDC Equity recognized during the time prior to 2007 when we were a taxable entity. These amounts are included in our tariff rates and are recovered over the depreciable lives of the asset in which they apply.

Unamortized loss on reacquired debt

Amounts represent the deferred and unamortized portion of loss on reacquired debt which are recovered in our rates. Amounts are amortized over the original life of the debt issue, or in the case of refinanced debt, over the life of the new debt issue.

Postretirement Benefits

Amount represents unrecognized gains and losses related to our postretirement benefit plan.

Regulatory Assets Amortization

Our amortization of the regulatory assets for the four months ended December 31, 2016 was $1 million related to deferred losses on reacquired debt included in "Interest, net" on our accompanying Consolidated Statement of Income.

Regulatory Matters

Rate Case

On January 31, 2013, the FERC approved our request to amend our January 2010 rate settlement with our customers. The amendment extended the required filing date for our rate case from February 28, 2013 to no later than May 31, 2013. On May 2, 2013, we filed a comprehensive settlement with our customers to resolve all matters relating to our rates. The FERC approved the comprehensive settlement on July 12, 2013. Under the settlement, customers were required to extend all firm service agreements through August 31, 2016. The settlement also includes a two-phase reduction in rates. The first phase, effective September 1, 2013, resulted in an approximately $11 million revenue reduction for 2013 and an additional revenue reduction of approximately $23 million for 2014. The second phase, effective November 1, 2015, resulted in an additional revenue reduction of approximately $2 million for 2015 and an additional revenue reduction of approximately $12 million in 2016 of which $2 million was incurred during the four months ended December 31, 2016. The settlement prohibited both us and our customers from requesting a change to our rates during a three-year moratorium through August 31, 2016 and requires us to file a new rate case to be effective no later than September 1, 2018.

Other

We applied with the FERC on May 30, 2014 in Docket No. CP14-493 to expand our system to provide additional firm transportation service of up to 240 thousand dekatherms per day to nine of our existing customers and one new customer ("Zone 3 Expansion Project"). The FERC cited nexus between our Zone 3 Expansion Project and a project by our affiliate Elba Express Company, L.L.C. ("EEC Expansion Project"), and determined that an order approving our project would not be issued until FERC was also able to rule on the EEC Expansion Project. On June 1, 2016, the FERC issued orders approving both the EEC Expansion Project and our Zone 3 Expansion Project. Our Zone 3 Expansion Project and the related EEC Expansion Project went in service on December 1, 2016.

9. Litigation, Environmental and Commitments

We are party to various legal, regulatory and other matters arising from the day-to-day operations of our businesses that may result in claims against the Company. Although no assurance can be given, we believe, based on our experiences to date and taking into account established reserves, that the ultimate resolution of such items will not have a material adverse impact on our business, financial position, results of operations or cash flows. We believe we have meritorious defenses to the matters to which we are a party and intend to vigorously defend the Company. When we determine a loss is probable of occurring and is reasonably estimable, we accrue an undiscounted liability for such contingencies based on our best estimate using information available at that time. If the estimated loss is a range of potential outcomes and there is no better estimate within the range, we accrue the amount at the low end of the range. We disclose contingencies where an adverse outcome may be material, or in the judgment of management, we conclude the matter should otherwise be disclosed.

Legal Proceedings

Cliffs Natural Resources (Cliffs)

We are engaged in a lawsuit against Cliffs in the Circuit Court of Jefferson County, Alabama (Case No. 68-CV-2014-900533) to determine whether Cliffs' longwall coal mining operations require the relocation of a large segment of our pipelines in Jefferson County, Alabama and who will be responsible for the cost of any such relocation. Prior to the initiation of the lawsuit, Cliffs notified us of its intent to conduct underground longwall coal mining operations in the vicinity of four of our pipelines in Jefferson County. Upon being informed by Cliffs that its planned coal mining operations would cause surface subsidence of three to six feet, we determined that such level of subsidence presented a safety hazard to our pipelines and that relocating the affected pipelines may be the safest and most economical option to mitigate the safety hazard. We allege in the lawsuit that easements governing our property rights to operate our pipelines do not allow Cliffs' mining operations to proceed as planned. We also allege, among other things, that if Cliffs is allowed to proceed with its mining plan, Cliffs should be responsible for the pipeline relocation costs and any other damages, which are expected to total approximately $33 million. We have completed the relocation of the pipelines to avoid the mining threat.

General

As of December 31, 2016, we had less than $1 million accrued for our outstanding legal proceedings.

Environmental Matters

We are subject to environmental cleanup and enforcement actions from time to time. In particular, the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) generally imposes joint and several liability for cleanup and enforcement costs on current and predecessor owners and operators of a site, among others, without regard to fault or the legality of the original conduct, subject to the right of a liable party to establish a "reasonable basis" for apportionment of costs. Our operations are also subject to federal, state and local laws and regulations relating to protection of the environment. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in our operations, and there can be no assurance that we will not incur significant costs and liabilities. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies under the terms of authority of those laws, and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us.

Southeast Louisiana Flood Protection Litigation

On July 24, 2013, the Board of Commissioners of the Southeast Louisiana Flood Protection Authority - East (SLFPA) filed a petition for damages and injunctive relief in state district court for Orleans Parish, Louisiana (Case No. 13-6911) against us, and approximately 100 other energy companies, alleging that defendants' drilling, dredging, pipeline and industrial operations since the 1930's have caused direct land loss and increased erosion and submergence resulting in alleged increased storm surge

risk, increased flood protection costs and unspecified damages to the plaintiff. The SLFPA asserts claims for negligence, strict liability, public nuisance, private nuisance, and breach of contract. Among other relief, the petition seeks unspecified monetary damages, attorney fees, interest, and injunctive relief in the form of abatement and restoration of the alleged coastal land loss including but not limited to backfilling and re-vegetation of canals, wetlands and reef creation, land bridge construction, hydrologic restoration, shoreline protection, structural protection, and bank stabilization. On August 13, 2013, the suit was removed to the U.S. District Court for the Eastern District of Louisiana. On February 13, 2015, the Court granted defendants' motion to dismiss the suit for failure to state a claim, and issued an order dismissing the SLFPA's claims with prejudice. The SLFPA filed a notice of appeal on February 20, 2015. The U.S. Court of Appeals for the Fifth Circuit heard oral argument on February 29, 2016 and we await the Court's decision.

Vintage Assets, Inc. Coastal Erosion Litigation

On December 18, 2015, Vintage Assets, Inc. filed a petition in the 25th Judicial District Court for Plaquemines Parish, Louisiana alleging that its 5,000 acre property is composed of coastal wetlands, and that SNG and certain other defendants failed to maintain pipeline canals and banks, causing widening of the canals, land loss, and damage to the ecology and hydrology of the marsh, in breach of right of way agreements, prudent operating practices, and Louisiana law. The suit also claims that defendants' alleged failure to maintain pipeline canals and banks constitutes negligence and has resulted in encroachment of the canals, constituting trespass. The suit seeks in excess of $80 million in money damages, including recovery of litigation costs, damages for trespass, and money damages associated with an alleged loss of natural resources and projected reconstruction cost of replacing or restoring wetlands. The suit was removed to the U.S. District Court for the Eastern District of Louisiana. Our assets at issue were sold to Highpoint Gas Transmission, LLC in 2011, which was subsequently purchased by American Midstream Partners, LP. In response to our demand for defense and indemnity, American Midstream Partners agreed to pay 50% of joint defense costs and expenses, with a percentage of indemnity to be determined upon final resolution of the suit. On October 20, 2016, plaintiffs filed an amended complaint naming Highpoint Gas Transmission, LLC as an additional defendant. A non-jury trial is scheduled to begin on September 11, 2017 and we intend to vigorously defend the suit.

Superfund Matters

Included in our recorded environmental liabilities are projects where we have received notice that we have been designated or could be designated as a Potentially Responsible Party (PRP) under CERCLA, commonly known as Superfund, or state equivalents for one active site. Liability under the federal CERCLA statute may be joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. We consider the financial strength of other PRPs in estimating our liabilities.

General

Although it is not possible to predict the ultimate outcomes, we believe that the resolution of the environmental matters set forth in this note, and other matters to which we and our subsidiary are a party, will not have a material adverse effect on our business, financial position, results of operations or cash flows. As of December 31, 2016, we had less than $1 million accrued for our environmental matters.

Commitments

Capital Commitments

As of December 31, 2016, we have capital commitments of $7 million, which we expect to spend during 2017. We have other planned capital and investment projects that are discretionary in nature, with no substantial contractual capital commitments made in advance of the actual expenditures.

Storage Commitments

We have storage capacity commitments totaling $7 million as of December 31, 2016, most of which are related to storage capacity contracts with our affiliate, Bear Creek, which we expect to spend during 2017. We expect annual renewal of this contract to occur into the foreseeable future.

Operating Leases

We lease property, facilities and equipment under various operating leases. Our primary commitment under operating leases is the lease of our office space in Birmingham, Alabama. Our future minimum annual rental commitments under our operating leases as of December 31, 2016, are as follows (in millions):

Year	Total
2017	$ 1
2018	2
2019	2
2020	2
2021	2
Thereafter	13
Total	$ 22

Rent expense on our lease obligations for the four months ended December 31, 2016 was approximately $1 million, and is reflected in "Operations and maintenance" on our accompanying Consolidated Statement of Income. While we hold the contractual obligations for the operating leases, the rent expense, which is considered a shared services cost and allocated to various KMI subsidiaries, is administered and funded by KMI.

10. Recent Accounting Pronouncements

Accounting Standards Updates

Topic 606

On May 28, 2014, the FASB issued ASU No. 2014-09, " *Revenue from Contracts with Customers* " followed by a series of related accounting standard updates (collectively referred to as "Topic 606"). Topic 606 is designed to create greater revenue recognition and disclosure comparability in financial statements. The provisions of Topic 606 include a five-step process by which an entity will determine revenue recognition, depicting the transfer of goods or services to customers in amounts reflecting the payment to which an entity expects to be entitled in exchange for those goods or services. Topic 606 requires certain disclosures about contracts with customers and provides more comprehensive guidance for transactions such as service revenue, contract modifications, and multiple-element arrangements.

We are in the process of comparing our current revenue recognition policies to the requirements of Topic 606 for each of our revenue categories. While we have not identified any material differences in the amount and timing of revenue recognition for the categories we have reviewed to date, our evaluation is not complete and we have not concluded on the overall impacts of adopting Topic 606. Topic 606 will require that our revenue recognition policy disclosure include further detail regarding our performance obligations as to the nature, amount, timing, and estimates of revenue and cash flows generated from our contracts with customers. Topic 606 will also require disclosure of significant changes in contract asset and contract liability balances period to period and the amount of the transaction price allocated to performance obligations that are unsatisfied (or partially unsatisfied) as of the end of the reporting period, as applicable. We will adopt Topic 606 effective January 1, 2018. Topic 606 provides for adoption either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption. We plan to make a determination as to our method of adoption once we more fully complete our

evaluation of the impacts of the standard on our revenue recognition and we are better able to evaluate the cost-benefit of each method.

ASU No. 2014-15

On August 27, 2014, the FASB issued ASU No. 2014-15, " *Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern* ." This ASU provides guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures if management concludes that substantial doubt exists or that its plans alleviate substantial doubt that was raised. We adopted ASU 2014-15 in 2016 with no impact to our financial statements.

ASU No. 2016-02

On February 25, 2016, the FASB issued ASU No. 2016-02, " *Leases (Topic 842)* ." This ASU requires that lessees will be required to recognize assets and liabilities on the balance sheet for the present value of the rights and obligations created by all leases with terms of more than 12 months. The ASU also will require disclosures designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. ASU No. 2016-02 will be effective for us as of January 1, 2019. We are currently reviewing the effect of ASU No. 2016-02.

ASU No. 2016-15

On August 26, 2016, the FASB issued ASU 2016-15, " *Statement of Cash Flows - Classification of Certain Cash Receipts and Cash Payments (Topic 230)* ." This ASU is intended to reduce the diversity in practice around how certain transactions are classified within the statement of cash flows. We adopted ASU No. 2016-15 in the third quarter of 2016 with no material impact to our financial statements.

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2017

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _____to ______

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-3526	**The Southern Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-0690070
1-3164	**Alabama Power Company** (An Alabama Corporation) 600 North 18 th Street Birmingham, Alabama 35203 (205) 257-1000	63-0004250
1-6468	**Georgia Power Company** (A Georgia Corporation) 241 Ralph McGill Boulevard, N.E. Atlanta, Georgia 30308 (404) 506-6526	58-0257110
001-31737	**Gulf Power Company** (A Florida Corporation) One Energy Place Pensacola, Florida 32520 (850) 444-6111	59-0276810
001-11229	**Mississippi Power Company** (A Mississippi Corporation) 2992 West Beach Boulevard Gulfport, Mississippi 39501 (228) 864-1211	64-0205820
001-37803	**Southern Power Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-2598670
1-14174	**Southern Company Gas** (A Georgia Corporation) Ten Peachtree Place, N.E. Atlanta, Georgia 30309 (404) 584-4000	58-2210952

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Registrant	**Large Accelerated Filer**	**Accelerated Filer**	**Non-accelerated Filer**	**Smaller Reporting Company**	**Emerging Growth Company**
The Southern Company	X				
Alabama Power Company			X		
Georgia Power Company			X		
Gulf Power Company			X		
Mississippi Power Company			X		
Southern Power Company			X		
Southern Company Gas			X		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑ (Response applicable to all registrants.)

Registrant	**Description of Common Stock**	**Shares Outstanding at June 30, 2017**
The Southern Company	**Par Value $5 Per Share**	**999,474,028**
Alabama Power Company	**Par Value $40 Per Share**	**30,537,500**
Georgia Power Company	**Without Par Value**	**9,261,500**
Gulf Power Company	**Without Par Value**	**7,392,717**
Mississippi Power Company	**Without Par Value**	**1,121,000**
Southern Power Company	**Par Value $0.01 Per Share**	**1,000**
Southern Company Gas	**Par Value $0.01 Per Share**	**100**

This combined Form 10-Q is separately filed by The Southern Company, Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, Southern Power Company, and Southern Company Gas. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other registrants.

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DEFINITIONS

Term	Meaning
2012 MPSC CPCN Order	A detailed order issued by the Mississippi PSC in April 2012 confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC
2013 ARP	Alternative Rate Plan approved by the Georgia PSC in 2013 for Georgia Power for the years 2014 through 2016 and subsequently extended through 2019
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Atlanta Gas Light	Atlanta Gas Light Company, a wholly-owned subsidiary of Southern Company Gas
Baseload Act	State of Mississippi legislation designed to enhance the Mississippi PSC's authority to facilitate development and construction of baseload generation in the State of Mississippi
CCR	Coal combustion residuals
Clean Power Plan	Final action published by the EPA in 2015 that established guidelines for states to develop plans to meet EPA-mandated CO_2 emission rates or emission reduction goals for existing electric generating units
CO_2	Carbon dioxide
COD	Commercial operation date
Contractor Settlement Agreement	The December 31, 2015 agreement between Westinghouse and the Vogtle Owners resolving disputes between the Vogtle Owners and the EPC Contractor under the Vogtle 3 and 4 Agreement
CPCN	Certificate of public convenience and necessity
CWIP	Construction work in progress
Dalton Pipeline	A 50% undivided ownership interest of Southern Company Gas in a pipeline facility in Georgia
DOE	U.S. Department of Energy
ECO Plan	Mississippi Power's Environmental Compliance Overview Plan
Eligible Project Costs	Certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Title XVII Loan Guarantee Program
EPA	U.S. Environmental Protection Agency
EPC Contractor	Westinghouse and its affiliate, WECTEC (formerly known as CB&I Stone & Webster, Inc.), formerly a subsidiary of The Shaw Group Inc. and Chicago Bridge & Iron Company N.V.; the former engineering, procurement, and construction contractor for Plant Vogtle Units 3 and 4
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FFB	Federal Financing Bank
Fitch	Fitch Ratings, Inc.
Form 10-K	Annual Report on Form 10-K of Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and Southern Company Gas for the year ended December 31, 2016, as applicable
GAAP	U.S. generally accepted accounting principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
Heating Degree Days	A measure of weather, calculated when the average daily temperatures are less than 65 degrees Fahrenheit
Horizon Pipeline	Horizon Pipeline Company, LLC
IGCC	Integrated coal gasification combined cycle
IIC	Intercompany interchange contract
Illinois Commission	Illinois Commerce Commission, the state regulatory agency for Nicor Gas
IRC	Internal Revenue Code of 1986, as amended

DEFINITIONS
(continued)

Term	Meaning
IRS	Internal Revenue Service
ITC	Investment tax credit
Kemper IGCC	Mississippi Power's IGCC project in Kemper County, Mississippi
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LIFO	Last-in, first-out
LNG	Liquefied natural gas
LOCOM	Lower of weighted average cost or current market price
LTSA	Long-term service agreement
MATS rule	Mercury and Air Toxics Standards rule
Merger	The merger, effective July 1, 2016, of a wholly-owned, direct subsidiary of Southern Company with and into Southern Company Gas, with Southern Company Gas continuing as the surviving corporation
Mirror CWIP	A regulatory liability used by Mississippi Power to record customer refunds resulting from a 2015 Mississippi PSC order
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MRA	Municipal and Rural Associations
MW	Megawatt
natural gas distribution utilities	Southern Company Gas' seven natural gas distribution utilities (Nicor Gas, Atlanta Gas Light, Virginia Natural Gas, Elizabethtown Gas, Florida City Gas, Chattanooga Gas Company, and Elkton Gas)
NCCR	Georgia Power's Nuclear Construction Cost Recovery
New Jersey BPU	New Jersey Board of Public Utilities, the state regulatory agency for Elizabethtown Gas
Nicor Gas	Northern Illinois Gas Company, a wholly-owned subsidiary of Southern Company Gas
NRC	U.S. Nuclear Regulatory Commission
NYMEX	New York Mercantile Exchange, Inc.
OCI	Other comprehensive income
PennEast Pipeline	PennEast Pipeline Company, LLC
PEP	Mississippi Power's Performance Evaluation Plan
Piedmont	Piedmont Natural Gas Company, Inc.
Pivotal Utility Holdings	Pivotal Utility Holdings, Inc., a wholly-owned subsidiary of Southern Company Gas, doing business as Elizabethtown Gas, Elkton Gas, and Florida City Gas
Plant Vogtle Units 3 and 4	Two new nuclear generating units under construction at Georgia Power's Plant Vogtle
PowerSecure	PowerSecure, Inc.
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 agreements, as well as, for Southern Power, contracts for differences that provide the owner of a renewable facility a certain fixed price for the electricity sold to the grid
PSC	Public Service Commission
PTC	Production tax credit
Rate CNP	Alabama Power's Rate Certificated New Plant
Rate CNP Compliance	Alabama Power's Rate Certificated New Plant Compliance

DEFINITIONS
(continued)

Term	Meaning
Rate CNP PPA	Alabama Power's Rate Certificated New Plant Power Purchase Agreement
Rate ECR	Alabama Power's Rate Energy Cost Recovery
Rate NDR	Alabama Power's Rate Natural Disaster Reserve
Rate RSE	Alabama Power's Rate Stabilization and Equalization plan
registrants	Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and Southern Company Gas
ROE	Return on equity
S&P	S&P Global Ratings, a division of S&P Global Inc.
scrubber	Flue gas desulfurization system
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
SMEPA	South Mississippi Electric Power Association (now known as Cooperative Energy)
SNG	Southern Natural Gas Company, L.L.C.
Southern Company	The Southern Company
Southern Company Gas	Southern Company Gas and its subsidiaries
Southern Company Gas Capital	Southern Company Gas Capital Corporation, a 100%-owned subsidiary of Southern Company Gas
Southern Company system	Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), Southern Electric Generating Company, Southern Nuclear, SCS, Southern Communications Services, Inc., PowerSecure (as of May 9, 2016), and other subsidiaries
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
SouthStar	SouthStar Energy Services, LLC
STRIDE	Atlanta Gas Light's Strategic Infrastructure Development and Enhancement program
Toshiba	Toshiba Corporation, parent company of Westinghouse
Toshiba Guarantee	Certain payment obligations of the EPC Contractor guaranteed by Toshiba
traditional electric operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power
Triton	Triton Container Investments, LLC
Virginia Commission	Virginia State Corporation Commission, the state regulatory agency for Virginia Natural Gas
Virginia Natural Gas	Virginia Natural Gas, Inc., a wholly-owned subsidiary of Southern Company Gas
Vogtle 3 and 4 Agreement	Agreement entered into with the EPC Contractor in 2008 by Georgia Power, acting for itself and as agent for the Vogtle Owners, pursuant to which the EPC Contractor agreed to design, engineer, procure, construct, and test Plant Vogtle Units 3 and 4
Vogtle Owners	Georgia Power, Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners
WACOG	Weighted average cost of gas
WECTEC	WECTEC Global Project Services Inc.
Westinghouse	Westinghouse Electric Company LLC

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q contains forward-looking statements. Forward-looking statements include, among other things, statements concerning regulated rates, the strategic goals for the wholesale business, 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, financing activities, completion dates of construction projects, filings with state and federal regulatory authorities, federal income tax benefits, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws regulating emissions, discharges, and disposal to air, water, and land, and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, including potential tax reform legislation, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity and natural gas, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of natural gas and other fuels;
- limits on pipeline capacity;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development, construction, and operation of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction, operating, or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by any PSC);
- the impact of any inability or other failure of Toshiba to perform its obligations under the Toshiba Guarantee, including any effect on the construction of Plant Vogtle Units 3 and 4;
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any environmental performance standards and the requirements of tax credits and other incentives, and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of the Southern Company system's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- ongoing renewable energy partnerships and development agreements;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions;

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION
(continued)

- actions related to cost recovery for the Kemper IGCC, including ongoing settlement discussions, Mississippi PSC review of the prudence of Kemper IGCC costs and approval of further permanent rate recovery plans, and related legal or regulatory proceedings;
- the ability to successfully operate the electric utilities' generating, transmission, and distribution facilities and Southern Company Gas' natural gas distribution and storage facilities and the successful performance of necessary corporate functions;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- the inherent risks involved in transporting and storing natural gas;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the possibility that the anticipated benefits from the Merger cannot be fully realized or may take longer to realize than expected, the possibility that costs related to the integration of Southern Company and Southern Company Gas will be greater than expected, the ability to retain and hire key personnel and maintain relationships with customers, suppliers, or other business partners, and the diversion of management time on integration-related issues;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Southern Company system's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in Southern Company's and any of its subsidiaries' credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of Southern Company's electric utilities 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 Southern Company system's business resulting from incidents affecting the U.S. electric grid, natural gas pipeline infrastructure, or operation of generating or storage 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 registrants from time to time with the SEC.

The registrants expressly disclaim any obligation to update any forward-looking statements.

THE SOUTHERN COMPANY
AND SUBSIDIARY COMPANIES

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	**2017**	2016
	(in millions)		*(in millions)*	
Operating Revenues:				
Retail electric revenues	**$ 3,777**	$ 3,748	**$ 7,171**	$ 7,124
Wholesale electric revenues	**618**	446	**1,149**	842
Other electric revenues	**167**	166	**342**	348
Natural gas revenues	**684**	—	**2,214**	—
Other revenues	**184**	99	**326**	137
Total operating revenues	**5,430**	4,459	**11,202**	8,451
Operating Expenses:				
Fuel	**1,092**	1,023	**2,088**	1,934
Purchased power	**211**	189	**390**	354
Cost of natural gas	**232**	—	**951**	—
Cost of other sales	**114**	58	**203**	77
Other operations and maintenance	**1,301**	1,099	**2,631**	2,206
Depreciation and amortization	**754**	569	**1,469**	1,110
Taxes other than income taxes	**308**	255	**638**	511
Estimated loss on Kemper IGCC	**3,012**	81	**3,120**	134
Total operating expenses	**7,024**	3,274	**11,490**	6,326
Operating Income (Loss)	**(1,594)**	1,185	**(288)**	2,125
Other Income and (Expense):				
Allowance for equity funds used during construction	**58**	45	**115**	98
Earnings (loss) from equity method investments	**28**	(1)	**67**	(1)
Interest expense, net of amounts capitalized	**(424)**	(293)	**(840)**	(539)
Other income (expense), net	**(3)**	(28)	**(11)**	(56)
Total other income and (expense)	**(341)**	(277)	**(669)**	(498)
Earnings (Loss) Before Income Taxes	**(1,935)**	908	**(957)**	1,627
Income taxes (benefit)	**(587)**	261	**(273)**	479
Consolidated Net Income (Loss)	**(1,348)**	647	**(684)**	1,148
Less:				
Dividends on preferred and preference stock of subsidiaries	**11**	12	**22**	23
Net income attributable to noncontrolling interests	**22**	12	**17**	13
Consolidated Net Income (Loss) Attributable to Southern Company	**$ (1,381)**	$ 623	**$ (723)**	$ 1,112
Common Stock Data:				
Earnings (loss) per share —				
Basic	**$ (1.38)**	$ 0.67	**$ (0.73)**	$ 1.20
Diluted	**$ (1.37)**	$ 0.66	**$ (0.72)**	$ 1.20
Average number of shares of common stock outstanding (in millions)				
Basic	**998**	934	**996**	925
Diluted	**1,005**	940	**1,003**	931
Cash dividends paid per share of common stock	**$ 0.5800**	$ 0.5600	**$ 1.1400**	$ 1.1025

The accompanying notes as they relate to Southern Company are an integral part of these condensed consolidated financial statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	**2017**	2016
	(in millions)		*(in millions)*	
Consolidated Net Income (Loss)	**$ (1,348)**	$ 647	**$ (684)**	$ 1,148
Other comprehensive income (loss):				
Qualifying hedges:				
Changes in fair value, net of tax of $23, $(13), $17, and $(85), respectively	**38**	(20)	**29**	(137)
Reclassification adjustment for amounts included in net income, net of tax of $(25), $10, $(26), and $11, respectively	**(41)**	16	**(42)**	18
Pension and other postretirement benefit plans:				
Reclassification adjustment for amounts included in net income, net of tax of $1, $-, $1, and $1, respectively	**1**	1	**2**	2
Total other comprehensive income (loss)	**(2)**	(3)	**(11)**	(117)
Comprehensive Income (Loss)	**(1,350)**	644	**(695)**	1,031
Less:				
Dividends on preferred and preference stock of subsidiaries	**11**	12	**22**	23
Comprehensive income attributable to noncontrolling interests	**22**	12	**17**	13
Consolidated Comprehensive Income (Loss) Attributable to Southern Company	**$ (1,383)**	$ 620	**$ (734)**	$ 995

The accompanying notes as they relate to Southern Company are an integral part of these condensed consolidated financial statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Six Months Ended June 30,	
	2017	2016
	(in millions)	
Operating Activities:		
Consolidated net income (loss)	**$ (684)**	$ 1,148
Adjustments to reconcile consolidated net income (loss) to net cash provided from operating activities —		
Depreciation and amortization, total	**1,683**	1,306
Deferred income taxes	**(270)**	279
Allowance for equity funds used during construction	**(115)**	(98)
Pension, postretirement, and other employee benefits	**(83)**	(56)
Settlement of asset retirement obligations	**(87)**	(66)
Stock based compensation expense	**73**	69
Hedge settlements	**1**	(201)
Estimated loss on Kemper IGCC	**3,120**	134
Income taxes receivable, non-current	**(58)**	—
Other, net	**(63)**	63
Changes in certain current assets and liabilities —		
-Receivables	**110**	(197)
-Prepayments	**(61)**	(28)
-Fossil fuel for generation	**6**	70
-Natural gas for sale, net of temporary LIFO liquidation	**223**	—
-Other current assets	**(36)**	(25)
-Accounts payable	**(353)**	(71)
-Accrued taxes	**(132)**	74
-Accrued compensation	**(331)**	(222)
-Retail fuel cost over recovery	**(187)**	(54)
-Other current liabilities	**(14)**	15
Net cash provided from operating activities	**2,742**	2,140
Investing Activities:		
Business acquisitions, net of cash acquired	**(1,062)**	(897)
Property additions	**(3,398)**	(3,486)
Investment in restricted cash	**(16)**	(8,608)
Distribution of restricted cash	**27**	649
Nuclear decommissioning trust fund purchases	**(388)**	(585)
Nuclear decommissioning trust fund sales	**383**	580
Cost of removal, net of salvage	**(128)**	(99)
Change in construction payables, net	**(117)**	(260)
Investment in unconsolidated subsidiaries	**(116)**	—
Payments pursuant to LTSAs	**(132)**	(82)
Other investing activities	**58**	113
Net cash used for investing activities	**(4,889)**	(12,675)
Financing Activities:		
Increase in notes payable, net	**30**	471
Proceeds —		
Long-term debt	**2,958**	12,038
Common stock	**417**	1,383
Short-term borrowings	**1,004**	—
Redemptions and repurchases —		
Long-term debt	**(1,478)**	(1,272)
Preference stock	**(150)**	—
Short-term borrowings	**—**	(475)
Distributions to noncontrolling interests	**(40)**	(11)

Capital contributions from noncontrolling interests		**73**		179
Purchase of membership interests from noncontrolling interests		**—**		(129)
Payment of common stock dividends		**(1,134)**		(1,023)
Other financing activities		**(75)**		(133)
Net cash provided from financing activities		**1,605**		11,028
Net Change in Cash and Cash Equivalents		**(542)**		493
Cash and Cash Equivalents at Beginning of Period		**1,975**		1,404
Cash and Cash Equivalents at End of Period	**$**	**1,433**	$	1,897
Supplemental Cash Flow Information:				
Cash paid (received) during the period for —				
Interest (net of $55 and $61 capitalized for 2017 and 2016, respectively)	**$**	**833**	$	458
Income taxes, net		**1**		(138)
Noncash transactions — Accrued property additions at end of period		**629**		549

The accompanying notes as they relate to Southern Company are an integral part of these condensed consolidated financial statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Assets	**At June 30, 2017**	At December 31, 2016
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 1,433**	$ 1,975
Receivables —		
Customer accounts receivable	**1,600**	1,565
Energy marketing receivables	**482**	623
Unbilled revenues	**593**	706
Under recovered regulatory clause revenues	**26**	18
Income taxes receivable, current	**544**	544
Other accounts and notes receivable	**513**	377
Accumulated provision for uncollectible accounts	**(52)**	(43)
Materials and supplies	**1,461**	1,462
Fossil fuel for generation	**624**	689
Natural gas for sale	**477**	631
Prepaid expenses	**361**	364
Other regulatory assets, current	**569**	581
Other current assets	**206**	230
Total current assets	**8,837**	9,722
Property, Plant, and Equipment:		
In service	**101,021**	98,416
Less: Accumulated depreciation	**30,667**	29,852
Plant in service, net of depreciation	**70,354**	68,564
Nuclear fuel, at amortized cost	**892**	905
Construction work in progress	**7,440**	8,977
Total property, plant, and equipment	**78,686**	78,446
Other Property and Investments:		
Goodwill	**6,271**	6,251
Equity investments in unconsolidated subsidiaries	**1,632**	1,549
Other intangible assets, net of amortization of $126 and $62 at June 30, 2017 and December 31, 2016, respectively	**929**	970
Nuclear decommissioning trusts, at fair value	**1,722**	1,606
Leveraged leases	**782**	774
Miscellaneous property and investments	**230**	270
Total other property and investments	**11,566**	11,420
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**1,325**	1,629
Unamortized loss on reacquired debt	**215**	223
Other regulatory assets, deferred	**6,668**	6,851
Other deferred charges and assets	**1,387**	1,406
Total deferred charges and other assets	**9,595**	10,109
Total Assets	**$ 108,684**	$ 109,697

The accompanying notes as they relate to Southern Company are an integral part of these condensed consolidated financial statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholders' Equity	At June 30, 2017	At December 31, 2016
	(in millions)	
Current Liabilities:		
Securities due within one year	$ **3,031**	$ 2,587
Notes payable	**3,274**	2,241
Energy marketing trade payables	**534**	597
Accounts payable	**1,920**	2,228
Customer deposits	**546**	558
Accrued taxes —		
Accrued income taxes	**125**	193
Unrecognized tax benefits	**400**	385
Other accrued taxes	**490**	667
Accrued interest	**508**	518
Accrued compensation	**584**	915
Asset retirement obligations, current	**300**	378
Liabilities from risk management activities, net of collateral	**71**	107
Acquisitions payable	**—**	489
Other regulatory liabilities, current	**169**	236
Other current liabilities	**799**	818
Total current liabilities	**12,751**	12,917
Long-term Debt	**43,885**	42,629
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**13,529**	14,092
Deferred credits related to income taxes	**212**	219
Accumulated deferred ITCs	**2,301**	2,228
Employee benefit obligations	**2,156**	2,299
Asset retirement obligations, deferred	**4,297**	4,136
Accrued environmental remediation	**399**	397
Other cost of removal obligations	**2,706**	2,748
Other regulatory liabilities, deferred	**233**	258
Other deferred credits and liabilities	**805**	880
Total deferred credits and other liabilities	**26,638**	27,257
Total Liabilities	**83,274**	82,803
Redeemable Preferred Stock of Subsidiaries	**118**	118
Redeemable Noncontrolling Interests	**51**	164
Stockholders' Equity:		
Common Stockholders' Equity:		
Common stock, par value $5 per share —		
Authorized — 1.5 billion shares		
Issued — June 30, 2017: 1.0 billion shares		
— December 31, 2016: 991 million shares		
Treasury — June 30, 2017: 0.9 million shares		
— December 31, 2016: 0.8 million shares		
Par value	**4,997**	4,952
Paid-in capital	**10,106**	9,661
Treasury, at cost	**(34)**	(31)
Retained earnings	**8,494**	10,356
Accumulated other comprehensive loss	**(191)**	(180)
Total Common Stockholders' Equity	**23,372**	24,758
Preferred and Preference Stock of Subsidiaries	**462**	609
Noncontrolling Interests	**1,407**	1,245
Total Stockholders' Equity	**25,241**	26,612

Total Liabilities and Stockholders' Equity	**$ 108,684**	$ 109,697

The accompanying notes as they relate to Southern Company are an integral part of these condensed consolidated financial statements.

SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

SECOND QUARTER 2017 vs. SECOND QUARTER 2016
AND
YEAR-TO-DATE 2017 vs. YEAR-TO-DATE 2016

OVERVIEW

Southern Company is a holding company that owns all of the common stock of the traditional electric operating companies and the parent entities of Southern Power and Southern Company Gas and owns other direct and indirect subsidiaries. Discussion of the results of operations is focused on the Southern Company system's primary businesses of electricity sales by the traditional electric operating companies and Southern Power and the distribution of natural gas by Southern Company Gas. The four traditional electric operating companies are vertically integrated utilities providing electric service in four Southeastern states. Southern Power 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 natural gas distribution utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. Southern Company's other business activities include providing energy technologies and services to electric utilities and large industrial, commercial, institutional, and municipal customers. Customer solutions include distributed generation systems, utility infrastructure solutions, and energy efficiency products and services. Other business activities also include investments in telecommunications, leveraged lease projects, and gas storage facilities. For additional information, see BUSINESS – "The Southern Company System – Traditional Electric Operating Companies," " – Southern Power," " – Southern Company Gas," and " – Other Businesses" in Item 1 of the Form 10-K.

Southern Company continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, electric and natural gas system reliability, execution of major construction projects, and earnings per share.

Construction Program

See RESULTS OF OPERATIONS – " Estimated Loss on Kemper IGCC ," FUTURE EARNINGS POTENTIAL – " Construction Program ," and Note (B) to the Condensed Financial Statements under " Regulatory Matters – Georgia Power – Nuclear Construction " and " Integrated Coal Gasification Combined Cycle " herein for additional information regarding the construction program. For information about Southern Power's acquisitions and construction of renewable energy facilities, see Note (I) to the Condensed Financial Statements under " Southern Power " herein.

Kemper IGCC

On June 21, 2017, the Mississippi PSC stated its intent to issue an order (which occurred on July 6, 2017) directing Mississippi Power to pursue a settlement under which the Kemper County energy facility would be operated as a natural gas plant, rather than an IGCC plant, and address all issues associated with the Kemper IGCC (Kemper Settlement Order). The Kemper Settlement Order established a new docket for the purposes of pursuing a global settlement of costs of the Kemper IGCC (Kemper IGCC Settlement Docket). The Mississippi PSC requested any such proposed settlement agreement reflect: (i) at a minimum, no rate increase to Mississippi Power customers (with a rate reduction focused on residential customers encouraged); (ii) removal of all cost risk to customers associated with the Kemper IGCC gasifier and related assets; and (iii) modification or amendment of the CPCN for the Kemper IGCC to allow only for ownership and operation of a natural gas facility.

Although the ability to achieve a negotiated settlement is uncertain, Mississippi Power intends to pursue any available settlement alternatives. In addition, the Kemper Settlement Order provides that, in the event a settlement agreement is not reached, the Mississippi PSC reserves its right to take any appropriate steps, including issuing an order to show cause as to why the CPCN for the Kemper IGCC should not be revoked.

On June 28, 2017, Mississippi Power notified the Mississippi PSC that it would begin a process to suspend operations and start-up activities on the gasifier portion of the Kemper IGCC, given the uncertainty as to the future of the gasifier portion of the Kemper IGCC. Mississippi Power expects to continue to operate the combined cycle portion of the Kemper IGCC as it has done since August 2014.

At the time of project suspension, the total cost estimate for the Kemper IGCC was approximately $7.38 billion, including approximately $5.95 billion of costs subject to the construction cost cap, and was net of the $137 million in additional grants from the DOE received on April 8, 2016 (Additional DOE Grants). Mississippi Power recorded pre-tax charges to income for revisions to the cost estimate subject to the construction cost cap totaling $196 million ($121 million after tax) in the second quarter through May 31, 2017 and a total of $305 million ($188 million after tax) for year-to-date through May 31, 2017. In the aggregate, Mississippi Power incurred charges of $3.07 billion ($1.89 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through May 31, 2017. The May 31, 2017 cost estimate included approximately $175 million of estimated costs to be incurred beyond the then-estimated in-service date of June 30, 2017 that were expected to be subject to the $2.88 billion cost cap.

At June 30, 2017, approximately $3.3 billion in actual Kemper IGCC costs were not reflected in Mississippi Power's retail and wholesale rates, of which $0.5 billion was related to the combined cycle and associated facilities and $2.8 billion was related to the gasification portions of the Kemper IGCC.

While the ultimate disposition of the gasification portions of the Kemper IGCC remains subject to the Mississippi PSC's jurisdiction, including the potential resolution of the matters addressed in the Kemper Settlement Order, given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility, cost recovery of the gasification portions is no longer probable; therefore, Mississippi Power recorded an additional charge to income in June 2017 of $2.8 billion ($2.0 billion after tax), which includes estimated costs associated with the gasification portions of the plant and lignite mine. In the event the gasification portions of the project are ultimately canceled, additional pre-tax costs currently estimated at approximately $100 million to $200 million are expected to be incurred.

Total pre-tax charges to income for the estimated probable losses on the Kemper IGCC were $3.0 billion ($2.1 billion after tax) for the second quarter 2017 and $3.1 billion ($2.2 billion after tax) for the six months ended June 30, 2017. In the aggregate, since the Kemper IGCC project started, Mississippi Power has incurred charges of $6.0 billion ($3.9 billion after tax) through June 30, 2017.

As of June 30, 2017, Mississippi Power has recorded a total of approximately $1.3 billion in costs associated with the combined cycle portion of the Kemper IGCC including transmission and related regulatory assets, of which $0.8 billion is included in retail and wholesale rates. The $0.5 billion not included in current rates includes costs in excess of the original 2010 estimate for the combined cycle portion of the facility, as well as the 15% that was previously contracted to SMEPA. Mississippi Power has calculated the revenue requirements resulting from these remaining costs, using reasonable assumptions for amortization periods, and expects them to be recovered through rates consistent with the Mississippi PSC's requested settlement conditions. The ultimate outcome will be determined by the Mississippi PSC in the Kemper IGCC Settlement Docket proceedings.

For additional information on the Kemper IGCC, including information on the project economic viability analysis, pending lawsuits, and an ongoing SEC investigation, see Note 3 to the financial statements of Southern Company under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and FUTURE EARNINGS POTENTIAL – " Integrated Coal Gasification Combined Cycle " and "Other Matters" and Note (B) to the Condensed Financial Statements under " Integrated Coal Gasification Combined Cycle " herein.

Nuclear Construction

On March 29, 2017, the EPC Contractor filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. To provide for a continuation of work at Plant Vogtle Units 3 and 4, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into an interim assessment agreement with the EPC Contractor (Interim Assessment Agreement), which the bankruptcy court approved on March 30, 2017. On June 9, 2017, Georgia Power

and the other Vogtle Owners and Toshiba entered into a settlement agreement regarding the Toshiba Guarantee (Guarantee Settlement Agreement). Pursuant to the Guarantee Settlement Agreement, Toshiba acknowledged the amount of its obligation under the Toshiba Guarantee is $3.68 billion (Guarantee Obligations), of which Georgia Power's proportionate share is approximately $1.7 billion, and that the Guarantee Obligations exist regardless of whether Plant Vogtle Units 3 and 4 are completed. Additionally, on June 9, 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the EPC Contractor entered into a services agreement (Services Agreement), which was amended and restated on July 20, 2017, for the EPC Contractor to transition construction management of Plant Vogtle Units 3 and 4 to Southern Nuclear and to provide ongoing design, engineering, and procurement services to Southern Nuclear. On July 27, 2017, the Services Agreement, and the EPC Contractor's rejection of the Vogtle 3 and 4 Agreement, became effective upon approval by the DOE and the Interim Assessment Agreement expired pursuant to its terms. The Services Agreement will continue until the start-up and testing of Plant Vogtle Units 3 and 4 is complete and electricity is generated and sold from both units. The Services Agreement is terminable by the Vogtle Owners upon 30 days' written notice.

Georgia Power and the other Vogtle Owners are continuing to conduct comprehensive schedule and cost-to-complete assessments, as well as cancellation cost assessments, to determine the impact of the EPC Contractor's bankruptcy filing on the construction cost and schedule for Plant Vogtle Units 3 and 4. Georgia Power will continue working with the Georgia PSC and the other Vogtle Owners to determine future actions related to Plant Vogtle Units 3 and 4, including, but not limited to, the status of construction and rate recovery, and currently expects to include its recommendation in its seventeenth Vogtle Construction Monitoring (VCM) report to be filed with the Georgia PSC in late August 2017.

An inability or other failure by Toshiba to perform its obligations under the Guarantee Settlement Agreement could have a further material impact on the net cost to the Vogtle Owners to complete construction of Plant Vogtle Units 3 and 4 and, therefore, on Southern Company's financial statements. The ultimate outcome of these matters also is dependent on the completion of the assessments described above, as well as the related regulatory treatment, and cannot be determined at this time. See FUTURE EARNINGS POTENTIAL – " Construction Program – Nuclear Construction" herein for additional information on Plant Vogtle Units 3 and 4, including Georgia Power's preliminary cost-to-complete and cancellation cost assessments for Plant Vogtle Units 3 and 4.

RESULTS OF OPERATIONS

Net Income (Loss)

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(2,004)	N/M	$(1,835)	N/M

N/M - Not meaningful

Consolidated net loss attributable to Southern Company was $(1.4) billion ($(1.38) per share) for the second quarter 2017 compared to net income of $623 million ($0.67 per share) for the corresponding period in 2016 . The decrease was primarily due to charges of $3.0 billion and $81 million in the second quarter 2017 and 2016 , respectively, related to the Kemper IGCC at Mississippi Power. Also contributing to the change were increases in renewable energy sales at Southern Power, higher retail electric revenues resulting from increases in base rates, and $49 million in net income from Southern Company Gas, which was acquired on July 1, 2016, partially offset by higher interest expense.

Consolidated net loss attributable to Southern Company was $(723) million ($(0.73) per share) for year-to-date 2017 compared to net income of $1.1 billion ($1.20 per share) for the corresponding period in 2016 . The decrease was primarily due to charges of $3.1 billion and $134 million for year-to-date 2017 and 2016 , respectively, related to the Kemper IGCC at Mississippi Power. Also contributing to the change was $288 million in net income from Southern Company Gas, increases in renewable energy sales at Southern Power, and higher retail electric revenues

resulting from increases in base rates, partially offset by higher interest expense and a decrease in retail electric revenues resulting from milder weather for year-to-date 2017 compared to the corresponding period in 2016.

See Note (B) to the Condensed Financial Statements under " Integrated Coal Gasification Combined Cycle " herein for additional information regarding the Kemper IGCC and Note (I) to the Condensed Financial Statements under " Southern Company " herein for additional information on the Merger.

Retail Electric Revenues

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$29	0.8	$47	0.7

In the second quarter 2017 , retail electric revenues were $3.8 billion compared to $3.7 billion for the corresponding period in 2016 . For year-to-date 2017 , retail revenues were $7.2 billion compared to $7.1 billion for the corresponding period in 2016.

Details of the changes in retail electric revenues were as follows:

	Second Quarter 2017		Year-to-Date 2017	
	(in millions)	*(% change)*	*(in millions)*	*(% change)*
Retail electric – prior year	$ 3,748		$ 7,124	
Estimated change resulting from –				
Rates and pricing	81	2.2	200	2.8
Sales decline	(12)	(0.3)	(22)	(0.3)
Weather	(51)	(1.4)	(189)	(2.6)
Fuel and other cost recovery	11	0.3	58	0.8
Retail electric – current year	$ 3,777	0.8 %	$ 7,171	0.7 %

Revenues associated with changes in rates and pricing increased in the second quarter and year-to-date 2017 when compared to the corresponding periods in 2016 primarily due to a Rate RSE increase at Alabama Power effective January 1, 2017, the recovery of Plant Vogtle Units 3 and 4 construction financing costs under the NCCR tariff at Georgia Power, and an ECO Plan rate increase at Mississippi Power implemented in the third quarter 2016. Additionally, the second quarter 2017 increase was partially offset by the rate pricing effect of decreased customer usage and lower contributions from commercial and industrial customers under a rate plan for variable demand-driven pricing at Georgia Power.

See Note 3 to the financial statements of Southern Company under "Regulatory Matters – Alabama Power" and " – Georgia Power – Rate Plans" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements herein for additional information.

Revenues attributable to changes in sales decreased in the second quarter 2017 w hen compared to the corresponding period in 2016 . Industrial KWH sales decreased 0.8% in the second quarter 2017 primarily in the paper, primary metals, and transportation sectors, partially offset by increased sales in the chemicals sector. Despite a more stable dollar and improving global economy, the industrial sector remains constrained by economic policy uncertainty. Weather-adjusted residential KWH sales decreased 0.4% in the second quarter 2017 primarily due to decreased customer usage primarily resulting from increased efficiency improvements in residential appliances and lighting, partially offset by customer growth. Weather-adjusted commercial KWH sales were flat in the second quarter 2017 primarily due to decreased customer usage resulting from an increase in electronic commerce transactions and energy saving initiatives, offset by customer growth.

Revenues attributable to changes in sales decreased for year-to-date 2017 when compared to the corresponding period in 2016 . Industrial KWH sales decreased 1.5% for year-to-date 2017 primarily in the paper, stone, clay, and

glass, and transportation sectors. Despite a more stable dollar and improving global economy, the industrial sector remains constrained by economic policy uncertainty. Weather-adjusted commercial KWH sales decreased 0.9% for year-to-date 2017 primarily due to decreased customer usage resulting from an increase in electronic commerce transactions and energy saving initiatives, partially offset by customer growth. Weather-adjusted residential KWH sales increased 0.2% for year-to-date 2017 primarily due to customer growth, partially offset by decreased customer usage primarily resulting from efficiency improvements in residential appliances and lighting.

Fuel and other cost recovery revenues increased $11 million and $58 million in the second quarter and year-to-date 2017 , respectively, when compared to the corresponding periods in 2016 primarily due to an increase in natural gas prices. Electric rates for the traditional electric operating companies include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, includi ng the energy component of PPA costs, and do not affect net income. The traditional electric operating companies each have one or more regulatory mechanisms to recover other costs such as environmental and other compliance costs, storm damage, new plants, and PPA capacity costs.

Wholesale Electric Revenues

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$172	38.6	$307	36.5

Wholesale electric revenues consist of PPAs primarily with investor-owned utilities and electric cooperatives and short-term opportunity sales. Wholesale electric revenues from PPAs (other than solar and wind PPAs) have both capacity and energy components. Capacity revenues generally represent the greatest contribution to net income and are designed to provide recovery of fixed costs plus a return on investment. Energy revenues will vary depending on fuel prices, the market prices of wholesale energy compared to the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Electricity sales from solar and wind PPAs do not have a capacity charge and customers either purchase the energy output of a dedicated renewable facility through an energy charge or through a fixed price for electricity. As a result, Southern Company's ability to recover fixed and variable operations and maintenance expenses is dependent upon the level of energy generated from these facilities, which can be impacted by weather conditions, equipment performance, and other factors. Wholesale electric revenues at Mississippi Power include FERC-regulated municipal and rural association sales as well as market-based sales. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Southern Company system's variable cost to produce the energy.

In the second quarter 2017 , wholesale electric revenues were $618 million compared to $446 million for the corresponding period in 2016 . This increase was primarily related to a $158 million increase in energy revenues and a $14 million increase in capacity revenues. For year-to-date 2017 , wholesale electric revenues were $1.1 billion compared to $842 million for the corresponding period in 2016 . This increase was primarily related to a $276 million increase in energy revenues and a $31 million increase in capacity revenues. The increases in energy revenues primarily related to Southern Power increases in renewable energy sales arising from new solar and wind facilities, sales from new natural gas PPAs, and non-PPA revenues from short-term sales. The increases in capacity revenues primarily resulted from PPAs related to new natural gas facilities and additional customer load requirements at Southern Power.

Natural Gas Revenues

Natural gas revenues represent sales from the natural gas distribution utilities and certain non-regulated operations of Southern Company Gas. Following the Merger, $684 million and $2.2 billion of natural gas revenues are included in the consolidated statements of income for the second quarter and year-to-date 2017 , respectively.

See Note (I) to the Condensed Financial Statements under " Southern Company – Merger with Southern Company Gas " herein for additional information.

Other Revenues

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$85	85.9	$189	N/M

N/M - Not meaningful

In the second quarter 2017 , other revenues were $184 million compared to $99 million for the corresponding period in 2016 . For year-to-date 2017 , other revenues were $326 million compared to $137 million for the corresponding period in 2016 . These increases were primarily due to increases of $60 million and $130 million for the second quarter and year-to-date 2017 , respectively, from products and services at PowerSecure, which was acquired on May 9, 2016, and $32 million and $62 million for the second quarter and year-to-date 2017 , respectively, of revenues from gas marketing products and services at Southern Company Gas following the Merger.

See Note (I) to the Condensed Financial Statements under " Southern Company " herein for additional information on the Merger and the acquisition of PowerSecure.

Fuel and Purchased Power Expenses

	Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
	(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
Fuel	$ 69	6.7	$ 154	8.0
Purchased power	22	11.6	36	10.2
Total fuel and purchased power expenses	$ 91		$ 190	

In the second quarter 2017 , total fuel and purchased power expenses were $1.3 billion compared to $1.2 billion for the corresponding period in 2016 . The increase was primarily the result of a $154 million increase in the average cost of fuel and purchased power primarily due to higher natural gas prices, partially offset by a $63 million decrease primarily due to the volume of KWHs purchased.

For year-to-date 2017 , total fuel and purchased power expenses were $2.5 billion compared to $2.3 billion for the corresponding period in 2016 . The increase was primarily the result of a $277 million increase in the average cost of fuel and purchased power primarily due to higher natural gas prices, partially offset by an $87 million decrease primarily due to the volume of KWHs purchased.

Fuel and purchased power energy transactions at the traditional electric operating companies are generally offset by fuel revenues and do not have a significant impact on net income. See FUTURE EARNINGS POTENTIAL – " Regulatory Matters – Fuel Cost Recovery " herein for additional information. Fuel expenses incurred under Southern Power's PPAs are generally the responsibility of the counterparties and do not significantly impact net income.

SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Details of the Southern Company system's generation and purchased power were as follows:

	Second Quarter 2017	Second Quarter 2016	**Year-to-Date 2017**	Year-to-Date 2016
Total generation *(in billions of KWHs)*	**49**	45	**93**	89
Total purchased power *(in billions of KWHs)*	**3**	4	**7**	8
Sources of generation *(percent)* —				
Coal	**31**	32	**30**	30
Nuclear	**16**	16	**16**	17
Gas	**43**	48	**45**	47
Hydro	**3**	2	**3**	4
Other	**7**	2	**6**	2
Cost of fuel, generated *(in cents per net KWH)* —				
Coal	**2.77**	3.20	**2.82**	3.22
Nuclear	**0.80**	0.82	**0.80**	0.82
Gas	**2.94**	2.24	**2.93**	2.20
Average cost of fuel, generated *(in cents per net KWH)*	**2.49**	2.33	**2.49**	2.28
Average cost of purchased power *(in cents per net KWH)* (*)	**7.70**	5.03	**6.85**	5.14

(*) Average cost of purchased power includes fuel purchased by the Southern Company system for tolling agreements where power is generated by the provider.

Fuel

In the second quarter 2017 , fuel expense was $1.1 billion compared to $1.0 billion for the corresponding period in 2016 . The increase was primarily due to a 31.3% increase in the average cost of natural gas per KWH generated and a 3.0% increase in the volume of KWHs generated by coal, partially offset by a 13.4% decrease in the average cost of coal per KWH generated and a 4.8% decrease in the volume of KWHs generated by natural gas.

For year-to-date 2017 , fuel expense was $2.1 billion compared to $1.9 billion for the corresponding period in 2016 . The increase was primarily due to a 33.2% increase in the average cost of natural gas per KWH generated and a 4.1% increase in the volume of KWHs generated by coal, partially offset by a 12.4% decrease in the average cost of coal per KWH generated and a 6.6% decrease in the volume of KWHs generated by natural gas.

Purchased Power

In the second quarter 2017 , purchased power expense was $211 million compared to $189 million for the corresponding period in 2016 . The increase was primarily due to a 53.1% increase in the average cost per KWH purchased, primarily as a result of higher natural gas prices, partially offset by a 28.0% decrease in the volume of KWHs purchased.

For year-to-date 2017 , purchased power expense was $390 million compared to $354 million for the corresponding period in 2016 . The increase was primarily due to a 33.3% increase in the average cost per KWH purchased, primarily as a result of higher natural gas prices, partially offset by a 16.8% decrease in the volume of KWHs purchased.

Energy purchases will vary depending on demand for energy within the Southern Company system's electric service territory, the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, and the availability of the Southern Company system's generation.

Cost of Natural Gas

Cost of natural gas represents the cost of natural gas sold by the natural gas distribution utilities and certain non-regulated operations of Southern Company Gas. Following the Merger, $232 million and $951 million of natural gas costs were included in the consolidated statements of income for the second quarter and year-to-date 2017 , respectively.

See Note (I) to the Condensed Financial Statements under " Southern Company – Merger with Southern Company Gas " herein for additional information.

Cost of Other Sales

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$56	96.6%	$126	N/M

N/M - Not meaningful

In the second quarter 2017 , cost of other sales was $114 million compared to $58 million for the corresponding period in 2016 . For year-to-date 2017 , cost of other sales was $203 million compared to $77 million for the corresponding period in 2016 . These increases were primarily due to costs related to sales of products and services by PowerSecure, which was acquired on May 9, 2016, and costs related to gas marketing products and services at Southern Company Gas following the Merger. See Note (I) to the Condensed Financial Statements under " Southern Company " herein for additional information.

Other Operations and Maintenance Expenses

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$202	18.4	$425	19.3

In the second quarter 2017 , other operations and maintenance expenses were $1.3 billion compared to $1.1 billion for the corresponding period in 2016 . The increase was primarily due to $213 million in operations and maintenance expenses at Southern Company Gas following the Merger, a $19 million increase associated with new solar, wind, and gas facilities at Southern Power, and a $15 million increase in operations and maintenance expenses at PowerSecure, which was acquired on May 9, 2016. These increases were partially offset by a $24 million decrease in acquisition-related expenses and a $7 million decrease in scheduled outage and maintenance costs at generation facilities.

For year-to-date 2017 , other operations and maintenance expenses were $2.6 billion compared to $2.2 billion for the corresponding period in 2016 . The increase was primarily due to increases of $467 million and $36 million in operations and maintenance expenses from Southern Company Gas and PowerSecure, respectively, a $35 million increase associated with new solar, wind, and gas facilities at Southern Power, and $32.5 million resulting from the write-down of Gulf Power's ownership of Plant Scherer Unit 3 in accordance with a settlement agreement approved by the Florida PSC on April 4, 2017 (2017 Rate Case Settlement Agreement). These increases were partially offset by a $46 million decrease in scheduled outage and maintenance costs at generation facilities, a $26 million decrease in acquisition-related expenses, a $19 million increase in gains from sales of integrated transmission system assets at Georgia Power, a $16 million decrease in customer accounts, service, and sales costs primarily associated with demand-side management costs related to the timing of new programs at Georgia Power, and a $14 million decrease in employee compensation and benefits including pension costs.

See Note (B) to the Condensed Financial Statements under " Regulatory Matters – Gulf Power – Retail Base Rate Cases " herein for additional information regarding the 2017 Rate Case Settlement Agreement and Note (I) to the

Condensed Financial Statements under " Southern Company " herein for additional information related to the Merger and the acquisition of PowerSecure.

Depreciation and Amortization

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$185	32.5	$359	32.3

In the second quarter 2017 , depreciation and amortization was $754 million compared to $569 million for the corresponding period in 2016 . Following the Merger, $125 million in depreciation and amortization for Southern Company Gas is included in the consolidated statements of income for the second quarter 2017 . Additionally, the increase reflects $61 million related to additional plant in service at the traditional electric operating companies and Southern Power, partially offset by $8 million more of a reduction in depreciation in the second quarter 2017 compared to the corresponding period in 2016 at Gulf Power, as authorized in its 2013 rate case settlement approved by the Florida PSC.

For year-to-date 2017 , depreciation and amortization was $1.5 billion compared to $1.1 billion for the corresponding period in 2016 . Following the Merger, $244 million in depreciation and amortization for Southern Company Gas is included in the consolidated statements of income for year-to-date 2017 . Additionally, the increase reflects $122 million related to additional plant in service at the traditional electric operating companies and Southern Power, partially offset by $28 million more of a reduction in depreciation for year-to-date 2017 compared to the corresponding period in 2016 at Gulf Power, as authorized in its 2013 rate case settlement approved by the Florida PSC.

See Note 3 to the financial statements of Southern Company under "Regulatory Matters – Gulf Power – Retail Base Rate Cases" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under " Regulatory Matters – Gulf Power – Retail Base Rate Cases " herein for additional information. Also see Note (I) to the Condensed Financial Statements under " Southern Company – Merger with Southern Company Gas " herein for additional information.

Taxes Other Than Income Taxes

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$53	20.8	$127	24.9

In the second quarter 2017 , taxes other than income taxes were $308 million compared to $255 million for the corresponding period in 2016 . For year-to-date 2017 , taxes other than income taxes were $638 million compared to $511 million for the corresponding period in 2016 . These increases were primarily related to $44 million and $114 million in the second quarter and year-to-date 2017 , respectively, in taxes other than income taxes associated with Southern Company Gas following the Merger.

See Note (I) to the Condensed Financial Statements under " Southern Company – Merger with Southern Company Gas " herein for additional information.

Estimated Loss on Kemper IGCC

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$2,931	N/M	$2,986	N/M

N/M - Not meaningful

Prior to the project suspension on June 28, 2017, estimated probable losses on the Kemper IGCC of $196 million and $305 million were recorded at Mississippi Power in the second quarter and year-to-date 2017, respectively, compared to $81 million and $134 million in the second quarter and year-to-date 2016 , respectively. These losses reflected revisions of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC prior to project suspension in excess of the $2.88 billion cost cap established by the Mississippi PSC, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (Initial DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions).

While the ultimate disposition of the gasification portions of the Kemper IGCC remains subject to the Mississippi PSC's jurisdiction, including the potential resolution of the matters addressed in the Kemper Settlement Order, given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility, cost recovery of the gasification portions is no longer probable; therefore, Mississippi Power recorded an additional charge to income in June 2017 of $2.8 billion, which includes estimated costs associated with the gasification portions of the plant and lignite mine.

See FUTURE EARNINGS POTENTIAL – " Construction Program – Integrated Coal Gasification Combined Cycle " and Note (B) to the Condensed Financial Statements under " Integrated Coal Gasification Combined Cycle " herein for additional information.

Allowance for Equity Funds Used During Construction

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$13	28.9	$17	17.3

In the second quarter 2017 , AFUDC equity was $58 million compared to $45 million in the corresponding period in 2016 . For year-to-date 2017 , AFUDC equity was $115 million compared to $98 million in the corresponding period in 2016 . These increases primarily resulted from a higher AFUDC rate and an increase in Kemper IGCC CWIP subject to AFUDC prior to project suspension at Mississippi Power.

See FUTURE EARNINGS POTENTIAL – " Construction Program – Integrated Coal Gasification Combined Cycle " and Note (B) to the Condensed Financial Statements under " Integrated Coal Gasification Combined Cycle " herein for additional information.

Earnings from Equity Method Investments

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$29	N/M	$68	N/M

N/M - Not meaningful

In the second quarter and year-to-date 2017 , earnings from equity method investments were $28 million and $67 million , respectively, primarily related to earnings from Southern Company Gas' equity method investment in SNG effective September 2016.

See Note (I) to the Condensed Financial Statements under " Southern Company – Merger with Southern Company Gas " herein for additional information.

Interest Expense, Net of Amounts Capitalized

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$131	44.7	$301	55.8

In the second quarter 2017 , interest expense, net of amounts capitalized was $424 million compared to $293 million in the corresponding period in 2016 . For year-to-date 2017 , interest expense, net of amounts capitalized was $840 million compared to $539 million in the corresponding period in 2016 . These increases were primarily due to an increase in average outstanding long-term debt primarily related to the Merger and the funding of Southern Power's acquisitions and construction projects. In addition, following the Merger, $48 million and $94 million in interest expense of Southern Company Gas was included in the consolidated statements of income for the second quarter and year-to-date 2017 , respectively.

See Note (E) to the Condensed Financial Statements herein and Note (I) to the Condensed Financial Statements under " Southern Company – Merger with Southern Company Gas " herein for additional information.

Other Income (Expense), Net

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$25	89.3	$45	80.4

In the second quarter 2017 , other income (expense), net was $(3) million compared to $(28) million for the corresponding period in 2016 . For year-to-date 2017 , other income (expense), net was $(11) million compared to $(56) million for the corresponding period in 2016 . These changes were primarily due to expenses incurred in 2016 associated with bridge financing for the Merger. These changes also include increases of $99 million and $116 million in currency losses arising from a translation of euro-denominated fixed-rate notes into U.S. dollars for the second quarter and year-to-date 2017, respectively, fully offset by an equal change in gains on the foreign currency hedges that were reclassified from accumulated OCI into earnings at Southern Power.

See Note (H) to the Condensed Financial Statements under " Foreign Currency Derivatives " herein for additional information.

Income Taxes (Benefit)

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(848)	N/M	$(752)	N/M

N/M - Not meaningful

In the second quarter 2017 , income tax benefit was $587 million compared to income tax expense of $261 million for the corresponding period in 2016 . The decrease was primarily due to $865 million in tax benefits related to the estimated probable losses on the Kemper IGCC at Mississippi Power, partially offset by $31 million in taxes at Southern Company Gas following the Merger.

For year-to-date 2017 , income tax benefit was $273 million compared to income tax expense of $479 million for the corresponding period in 2016 , primarily due to $886 million in tax benefits related to the estimated probable losses on the Kemper IGCC at Mississippi Power. In addition, the change reflects $180 million in taxes at Southern Company Gas following the Merger, partially offset by a net increase in tax benefits of $16 million from renewable tax credits at Southern Power.

See Note (G) to the Condensed Financial Statements herein and Note (I) to the Condensed Financial Statements under " Southern Company – Merger with Southern Company Gas " herein for additional information.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Southern Company's future earnings potential. The level of Southern Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Southern Company system's primary businesses of selling electricity and distributing natural gas. These factors include the traditional electric operating companies' and the natural gas distribution utilities' ability to maintain a constructive regulatory environment that allows for the timely recovery of prudently-incurred costs during a time of increasing costs and limited projected demand growth over the next several years. Completion of cost assessments and the determination of future actions related to Plant Vogtle Units 3 and 4 construction and rate recovery and the ability to recover costs for the remainder of the Kemper County energy facility not included in current rates are also major factors. In addition, the profitability of Southern Power's competitive wholesale business and successful additional investments in renewable and other energy projects are also major factors.

Current proposals related to potential federal tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals, including any potential changes to the availability or realizability of ITCs and PTCs, is dependent on the final form of any legislation enacted and the related transition rules and cannot be determined at this time, but could have a material impact on Southern Company's financial statements.

Future earnings for the electricity and natural gas businesses will be driven primarily by customer growth. Earnings in the electricity business will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies, increasing volumes of electronic commerce transactions, and higher multi-family home construction. Earnings for both the electricity and natural gas businesses are subject to a variety of other factors. These factors include weather, competition, new energy contracts with other utilities and other wholesale customers, energy conservation practiced by customers, the use of alternative energy sources by customers, the prices of electricity and natural gas, the price elasticity of demand, and the rate of economic growth or decline in the service territory. In addition, the level of future earnings for the wholesale electric business also depends on numerous factors including regulatory matters, creditworthiness of customers, total electric generating capacity available and related costs, future acquisitions and construction of electric generating facilities, the impact of tax credits from renewable energy projects, and the successful remarketing of capacity as current contracts expire. Demand for electricity and natural gas is primarily driven by economic growth. The pace of economic growth and electricity and natural gas demand may be affected by changes

in regional and global economic conditions, which may impact future earnings. In addition, the volatility of natural gas prices has a significant impact on the natural gas distribution utilities' customer rates, long-term competitive position against other energy sources, and the ability of Southern Company Gas' gas marketing services and wholesale gas services businesses to capture value from locational and seasonal spreads. Additionally, changes in commodity prices subject a significant portion of Southern Company Gas' operations to earnings variability.

As part of its ongoing effort to adapt to changing market conditions, Southern Company continues to evaluate and consider a wide array of potential business strategies. These strategies may include business combinations, partnerships, and acquisitions involving other utility or non-utility businesses or properties, disposition of certain assets or businesses, internal restructuring, or some combination thereof. Furthermore, Southern Company may engage in new business ventures that arise from competitive and regulatory changes in the utility industry. Pursuit of any of the above strategies, or any combination thereof, may significantly affect the business operations, risks, and financial condition of Southern Company.

For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Southern Company in Item 7 of the Form 10-K and RISK FACTORS in Item 1A herein.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis for the traditional electric operating companies and the natural gas distribution utilities or through long-term wholesale agreements for the traditional electric operating companies and Southern Power. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are completed. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity and natural gas, which could negatively affect results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company in Item 7 and Note 3 to the financial statements of Southern Company under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

Environmental Statutes and Regulations

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Southern Company in Item 7 of the Form 10-K for additional information regarding the EPA's eight-hour ozone National Ambient Air Quality Standard (NAAQS).

On June 2, 2017, the EPA published a final rule redesignating a 15-county area within metropolitan Atlanta to attainment for the 2008 eight-hour ozone NAAQS.

On June 18, 2017, the EPA published a notice delaying attainment designations for the 2015 eight-hour ozone NAAQS by one year, setting a revised deadline of October 1, 2018. The ultimate outcome of this matter cannot be determined at this time.

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Southern Company in Item 7 of the Form 10-K for additional information regarding the final effluent guidelines rule and the final rule revising the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs.

On April 25, 2017, the EPA published a notice announcing it would reconsider the effluent guidelines rule, which had been finalized in November 2015. On June 6, 2017, the EPA proposed a rule establishing a stay of the compliance deadlines for certain effluent limitations and pretreatment standards under the rule.

On June 27, 2017, the EPA and the U.S. Army Corps of Engineers proposed to rescind the final rule that revised the regulatory definition of waters of the U.S. for all CWA programs. The final rule has been stayed since October 2015 by the U.S. Court of Appeals for the Sixth Circuit.

The ultimate outcome of these matters cannot be determined at this time.

Global Climate Issues

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" of Southern Company in Item 7 of the Form 10-K for additional information.

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. The executive order specifically directs the EPA to review the Clean Power Plan and final greenhouse gas emission standards for new, modified, and reconstructed electric generating units and, if appropriate, take action to suspend, revise, or rescind those rules.

On June 1, 2017, the U.S. President announced that the United States will withdraw from the non-binding Paris Agreement and begin renegotiation of its terms.

The ultimate outcome of these matters cannot be determined at this time.

FERC Matters

Market-Based Rate Authority

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters – Market-Based Rate Authority" of Southern Company in Item 7 of the Form 10-K for additional information regarding the traditional electric operating companies' and Southern Power's market power proceeding and amendment to their market-rate tariff.

On May 17, 2017, the FERC accepted the traditional electric operating companies' and Southern Power's compliance filing accepting the terms of the FERC's February 2, 2017 order regarding an amendment by the traditional electric operating companies and Southern Power to their market-based rate tariff. While the FERC's order references the traditional electric operating companies' and Southern Power's market power proceeding, it remains a separate, ongoing matter.

Southern Company Gas

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters – Southern Company Gas" of Southern Company in Item 7 and Note 4 to the financial statements of Southern Company in Item 8 of the Form 10-K for additional information regarding Southern Company Gas' pipeline projects.

On August 1, 2017, the Dalton Pipeline was placed in service as authorized by the FERC and transportation service for customers commenced.

Regulatory Matters

Fuel Cost Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Regulatory Matters – Fuel Cost Recovery" of Southern Company in Item 7 and Note 3 to the financial statements of Southern Company under "Regulatory Matters – Alabama Power – Rate ECR" and "Regulatory Matters – Georgia Power –

Fuel Cost Recovery" in Item 8 of the Form 10-K for additional information regarding fuel cost recovery for the traditional electric operating companies.

The traditional electric operating companies each have established fuel cost recovery rates approved by their respective state PSCs. Fuel cost recovery revenues are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect cash flow. The traditional electric operating companies continuously monitor their under or over recovered fuel cost balances and make appropriate filings with their state PSCs to adjust fuel cost recovery rates as necessary.

Renewables

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Regulatory Matters – Renewables" of Southern Company in Item 7 of the Form 10-K for additional information regarding the Southern Company system's renewables activity.

On May 16, 2017, the Georgia PSC approved Georgia Power's request to build, own, and operate a 139-MW solar generation facility at a U.S. Air Force base that is expected to be placed in service by the end of 2019.

During the six months ended June 30, 2017, Georgia Power continued construction of a 31-MW solar generation facility at a U.S. Marine Corps base that is expected to be placed in service in the fourth quarter 2017.

Mississippi Power placed in service two solar projects in January 2017 and June 2017. A third solar project is expected to be placed in service in the third quarter 2017. Mississippi Power may retire the renewable energy credits (REC) generated on behalf of its customers or sell the RECs, separately or bundled with energy, to third parties.

On June 9, 2017, Mississippi Power submitted a CPCN to the Mississippi PSC for the approval of construction, operation, and maintenance of a 52.5-MW solar energy generating facility, which, if approved, is expected to be placed in service by January 2020.

The ultimate outcome of these matters cannot be determined at this time.

Alabama Power

Alabama Power's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Alabama PSC. Alabama Power currently recovers its costs from the regulated retail business primarily through Rate RSE, Rate CNP, Rate ECR, and Rate NDR. In addition, the Alabama PSC issues accounting orders to address current events impacting Alabama Power. See Note 3 to the financial statements of Southern Company under "Regulatory Matters – Alabama Power" in Item 8 of the Form 10-K for additional information regarding Alabama Power's rate mechanisms and accounting orders. The recovery balance of each regulatory clause for Alabama Power is reported in Note (B) to the Condensed Financial Statements herein.

Georgia Power

Georgia Power's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Georgia PSC. Georgia Power currently recovers its costs from the regulated retail business through the 2013 ARP, which includes traditional base tariff rates, Demand-Side Management tariffs, Environmental Compliance Cost Recovery tariffs, and Municipal Franchise Fee tariffs. In addition, financing costs related to the construction of Plant Vogtle Units 3 and 4 are being collected through the NCCR tariff and fuel costs are collected through a separate fuel cost recovery tariff. See Note (B) to the Condensed Financial Statements under " Regulatory Matters – Georgia Power – Nuclear Construction " herein and Note 3 to the financial statements of Southern Company under "Regulatory Matters – Georgia Power – Nuclear Construction" in Item 8 of the Form 10-K for additional information regarding Georgia Power's NCCR tariff. Also see Note (B) to the Condensed Financial Statements under " Regulatory Matters – Georgia Power – Fuel Cost Recovery " herein for additional information regarding Georgia Power's fuel cost recovery.

Integrated Resource Plan

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Regulatory Matters – Georgia Power – Integrated Resource Plan" of Southern Company in Item 7 of the Form 10-K for additional information regarding Georgia Power's triennial Integrated Resource Plan.

On March 7, 2017, the Georgia PSC approved Georgia Power's decision to suspend work at a future generation site in Stewart County, Georgia, due to changing economics, including load forecasts and lower fuel costs. The timing of recovery for costs incurred of approximately $50 million will be determined by the Georgia PSC in a future base rate case. The ultimate outcome of this matter cannot be determined at this time.

Gulf Power

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Regulatory Matters – Gulf Power" of Southern Company in Item 7 of the Form 10-K for additional information regarding Gulf Power's October 2016 request to the Florida PSC to increase retail base rates and Gulf Power's ownership of Plant Scherer Unit 3.

On April 4, 2017, the Florida PSC approved the 2017 Rate Case Settlement Agreement among Gulf Power and three intervenors with respect to Gulf Power's request to increase retail base rates. Under the terms of the 2017 Rate Case Settlement Agreement, Gulf Power increased rates effective with the first billing cycle in July 2017 to provide an annual overall net customer impact of approximately $54.3 million. The net customer impact consists of a $62.0 million increase in annual base revenues less an annual equivalent credit of approximately $7.7 million for 2017 for certain wholesale revenues to be provided through December 2019 through the purchased power capacity cost recovery clause. In addition, Gulf Power continued its authorized retail ROE midpoint (10.25%) and range (9.25% to 11.25%) and is deemed to have an equity ratio of 52.5% for all retail regulatory purposes. Gulf Power will also begin amortizing the regulatory asset associated with the investment balances remaining after the retirement of Plant Smith Units 1 and 2 (357 MWs) over 15 years effective January 1, 2018 and will implement new depreciation rates effective January 1, 2018. The 2017 Rate Case Settlement Agreement also resulted in a $32.5 million write-down of Gulf Power's ownership of Plant Scherer Unit 3 (205 MWs), which was recorded in the first quarter 2017. The remaining issues related to the inclusion of Gulf Power's investment in Plant Scherer Unit 3 in retail rates have been resolved as a result of the 2017 Rate Case Settlement Agreement, including recoverability of certain costs associated with the ongoing ownership and operation of the unit through the environmental cost recovery clause rate approved by the Florida PSC in November 2016.

Southern Company Gas

Natural Gas Cost Recovery

Southern Company Gas has established natural gas cost recovery rates approved by the relevant state regulatory agencies in the states in which it serves. Natural gas cost recovery revenues are adjusted for differences in actual recoverable natural gas costs and amounts billed in current regulated rates. Changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect cash flows.

Base Rate Cases

On March 10, 2017, Nicor Gas filed a general base rate case with the Illinois Commission requesting a $208 million increase in annual base rate revenues. The requested increase is based on a 2018 projected test year and a ROE of 10.7%. The Illinois Commission is expected to rule on the requested increase within the 11-month statutory time limit, after which rate adjustments will be effective. The ultimate outcome of this matter cannot be determined at this time.

Construction Program

Overview

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. The Southern Company system intends to continue its strategy of developing and constructing new electric generating facilities, adding environmental modifications to certain existing units, expanding the electric transmission and distribution systems, and updating and expanding the natural gas distribution systems. For the traditional electric operating companies, major generation construction projects are subject to state PSC approval in order to be included in retail rates. While Southern Power generally constructs and acquires generation assets covered by long-term PPAs, any uncontracted capacity could negatively affect future earnings. Southern Company Gas is engaged in various infrastructure improvement programs designed to update or expand the natural gas distribution systems of the natural gas distribution utilities to improve reliability and meet operational flexibility and growth. The natural gas distribution utilities recover their investment and a return associated with these infrastructure programs through their regulated rates.

The largest construction project currently underway in the Southern Company system is Plant Vogtle Units 3 and 4 (45.7% ownership interest by Georgia Power in the two units, each with approximately 1,100 MWs). Georgia Power and the other Vogtle Owners are continuing to conduct comprehensive schedule and cost-to-complete assessments, as well as cancellation cost assessments, to determine the impact of the EPC Contractor's bankruptcy filing on the construction cost and schedule for Plant Vogtle Units 3 and 4. Georgia Power will continue working with the Georgia PSC and the other Vogtle Owners to determine future actions related to Plant Vogtle Units 3 and 4, including, but not limited to, the status of construction and rate recovery, and currently expects to include its recommendation in its seventeenth VCM report to be filed with the Georgia PSC in late August 2017. On June 21, 2017, the Mississippi PSC directed Mississippi Power to pursue a settlement under which the Kemper IGCC would be operated as a natural gas plant rather than an IGCC plant and, on June 28, 2017, Mississippi Power notified the Mississippi PSC that it would begin a process to suspend operations and start-up activities on the gasifier portion of the plant. See Note 3 to the financial statements of Southern Company under "Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under " Regulatory Matters – Georgia Power – Nuclear Construction " and " Integrated Coal Gasification Combined Cycle " herein for additional information. For additional information about costs relating to Southern Power's acquisitions that involve construction of renewable energy facilities, see Note 12 to the financial statements of Southern Company under "Southern Power – Construction Projects" in Item 8 of the Form 10-K and Note (I) to the Condensed Financial Statements under " Southern Power " herein. See Note 3 to the financial statements of Southern Company under "Regulatory Matters – Southern Company Gas – Regulatory Infrastructure Programs" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under " Regulatory Matters – Southern Company Gas – Regulatory Infrastructure Programs " herein for information regarding infrastructure improvement programs at the natural gas distribution utilities.

Also see FINANCIAL CONDITION AND LIQUIDITY – " Capital Requirements and Contractual Obligations " herein for additional information regarding Southern Company's capital requirements for its subsidiaries' construction programs.

Integrated Coal Gasification Combined Cycle

The Kemper IGCC was approved by the Mississippi PSC in the 2010 CPCN proceedings, subject to a construction cost cap of $2.88 billion, net of $245 million of Initial DOE Grants and excluding the Cost Cap Exceptions. The combined cycle and associated common facilities portion of the Kemper IGCC were placed in service in August 2014.

In December 2015, the Mississippi PSC issued an order (In-Service Asset Rate Order), based on a stipulation between Mississippi Power and the Mississippi Public Utilities Staff, authorizing rates that provide for the recovery of approximately $126 million annually related to the combined cycle and associated common facilities portion of Kemper IGCC assets previously placed in service. As required by the In-Service Asset Rate Order, on June 5, 2017,

Mississippi Power made a rate filing requesting to adjust the amortization schedules of the regulatory assets reviewed and determined prudent in a manner that would not change customer rates or annual revenues. On June 28, 2017, the Mississippi PSC suspended this filing. On July 6, 2017, the Mississippi PSC issued an order requiring Mississippi Power to establish a regulatory liability account to maintain current rates related to the Kemper IGCC following the July 2017 completion of the amortization period for certain regulatory assets approved in the In-Service Asset Rate Order that would allow for subsequent refund if the Mississippi PSC deems the rates unjust and unreasonable.

The remainder of the plant includes the gasifiers and the gas clean-up facilities. The initial production of syngas began on July 14, 2016 for gasifier "B" and on September 13, 2016 for gasifier "A." Mississippi Power achieved integrated operation of both gasifiers on January 29, 2017, including the production of electricity from syngas in both combustion turbines. During testing, the plant produced and captured CO_2, and produced sulfuric acid and ammonia, each of acceptable quality under the related off-take agreements. However, Mississippi Power experienced numerous challenges during the extended start-up process to achieve integrated operation of the gasifiers on a sustained basis. Most recently, in May 2017, after achieving these milestones, Mississippi Power determined that a critical system component, the syngas coolers, would need replacement sooner than originally planned, which would require significant lead time and significant cost. In addition, the long-term natural gas price forecast has decreased significantly and the estimated cost of operating and maintaining the facility during the first five full years of operations increased significantly since certification.

On June 21, 2017, the Mississippi PSC stated its intent to issue the Kemper Settlement Order (which occurred on July 6, 2017) directing Mississippi Power to pursue a settlement under which the Kemper County energy facility would be operated as a natural gas plant, rather than an IGCC plant, and address all issues associated with the Kemper IGCC. The Kemper Settlement Order established the Kemper IGCC Settlement Docket for the purposes of pursuing a global settlement of costs of the Kemper IGCC. The Mississippi PSC requested any such proposed settlement agreement reflect: (i) at a minimum, no rate increase to Mississippi Power customers (with a rate reduction focused on residential customers encouraged); (ii) removal of all cost risk to customers associated with the Kemper IGCC gasifier and related assets; and (iii) modification or amendment of the CPCN for the Kemper IGCC to allow only for ownership and operation of a natural gas facility. The Kemper Settlement Order provides that any related settlement agreement be filed within 45 days from the effective date of the Kemper Settlement Order. If a settlement agreement is filed, a hearing will be set 45 days from the date of the settlement's filing, and the appropriate scheduling order will be established.

Although the ability to achieve a negotiated settlement is uncertain, Mississippi Power intends to pursue any available settlement alternatives. In addition, the Kemper Settlement Order provides that, in the event a settlement agreement is not reached, the Mississippi PSC reserves its right to take any appropriate steps, including issuing an order to show cause as to why the CPCN for the Kemper IGCC should not be revoked.

On June 28, 2017, Mississippi Power notified the Mississippi PSC that it would begin a process to suspend operations and start-up activities on the gasifier portion of the Kemper IGCC, given the uncertainty as to the future of the gasifier portion of the Kemper IGCC. Mississippi Power expects to continue to operate the combined cycle portion of the Kemper IGCC as it has done since August 2014.

At the time of project suspension, the total cost estimate for the Kemper IGCC was approximately $7.38 billion, including approximately $5.95 billion of costs subject to the construction cost cap, and was net of the $137 million in Additional DOE Grants. Mississippi Power recorded pre-tax charges to income for revisions to the cost estimate subject to the construction cost cap totaling $196 million ($121 million after tax) in the second quarter through May 31, 2017 and a total of $305 million ($188 million after tax) for year-to-date through May 31, 2017. In the aggregate, Mississippi Power incurred charges of $3.07 billion ($1.89 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through May 31, 2017. The May 31, 2017 cost estimate included approximately $175 million of estimated costs to be incurred beyond the then-estimated in-service date of June 30, 2017 that were expected to be subject to the $2.88 billion cost cap.

At June 30, 2017, approximately $3.3 billion in actual Kemper IGCC costs were not reflected in Mississippi Power's retail and wholesale rates, of which $0.5 billion was related to the combined cycle and associated facilities and $2.8 billion was related to the gasification portions of the Kemper IGCC.

While the ultimate disposition of the gasification portions of the Kemper IGCC remains subject to the Mississippi PSC's jurisdiction, including the potential resolution of the matters addressed in the Kemper Settlement Order, given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility, cost recovery of the gasification portions is no longer probable; therefore, Mississippi Power recorded an additional charge to income in June 2017 of $2.8 billion ($2.0 billion after tax), which includes estimated costs associated with the gasification portions of the plant and lignite mine. In the event the gasification portions of the project are ultimately canceled, additional pre-tax costs currently estimated at approximately $100 million to $200 million are expected to be incurred.

Total pre-tax charges to income for the estimated probable losses on the Kemper IGCC were $3.0 billion ($2.1 billion after tax) for the second quarter 2017 and $3.1 billion ($2.2 billion after tax) for the six months ended June 30, 2017. In the aggregate, since the Kemper IGCC project started, Mississippi Power has incurred charges of $6.0 billion ($3.9 billion after tax) through June 30, 2017.

As of June 30, 2017, Mississippi Power has recorded a total of approximately $1.3 billion in costs associated with the combined cycle portion of the Kemper IGCC including transmission and related regulatory assets, of which $0.8 billion is included in retail and wholesale rates. The $0.5 billion not included in current rates includes costs in excess of the original 2010 estimate for the combined cycle portion of the facility, as well as the 15% that was previously contracted to SMEPA. Mississippi Power has calculated the revenue requirements resulting from these remaining costs, using reasonable assumptions for amortization periods, and expects them to be recovered through rates consistent with the Mississippi PSC's requested settlement conditions. The ultimate outcome will be determined by the Mississippi PSC in the Kemper IGCC Settlement Docket proceedings.

For additional information on the Kemper IGCC, including information on the project economic viability analysis, pending lawsuits, and an ongoing SEC investigation, see Note 3 to the financial statements of Southern Company under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and FUTURE EARNINGS POTENTIAL – " Integrated Coal Gasification Combined Cycle " and "Other Matters" and Note (B) to the Condensed Financial Statements under " Integrated Coal Gasification Combined Cycle " herein. Also see "Litigation" herein.

Litigation

On April 26, 2016, a complaint against Mississippi Power was filed in Harrison County Circuit Court (Circuit Court) by Biloxi Freezing & Processing Inc., Gulfside Casino Partnership, and John Carlton Dean, which was amended and refiled on July 11, 2016 to include, among other things, Southern Company as a defendant. The individual plaintiff alleges that Mississippi Power and Southern Company violated the Mississippi Unfair Trade Practices Act. All plaintiffs have alleged that Mississippi Power and Southern Company concealed, falsely represented, and failed to fully disclose important facts concerning the cost and schedule of the Kemper IGCC and that these alleged breaches have unjustly enriched Mississippi Power and Southern Company. The plaintiffs seek unspecified actual damages and punitive damages; ask the Circuit Court to appoint a receiver to oversee, operate, manage, and otherwise control all affairs relating to the Kemper IGCC; ask the Circuit Court to revoke any licenses or certificates authorizing Mississippi Power or Southern Company to engage in any business related to the Kemper IGCC in Mississippi; and seek attorney's fees, costs, and interest. The plaintiffs also seek an injunction to prevent any Kemper IGCC costs from being charged to customers through electric rates. On June 23, 2017, the Circuit Court ruled in favor of motions by Southern Company and Mississippi Power and dismissed the case. On July 7, 2017, the plaintiffs filed notice to appeal to the Mississippi Supreme Court.

On June 9, 2016, Treetop Midstream Services, LLC (Treetop) and other related parties filed a complaint against Mississippi Power, Southern Company, and SCS in the state court in Gwinnett County, Georgia. The complaint relates to the cancelled CO_2 contract with Treetop and alleges fraudulent misrepresentation, fraudulent concealment, civil conspiracy, and breach of contract on the part of Mississippi Power, Southern Company, and SCS and seeks

compensatory damages of $100 million, as well as unspecified punitive damages. Southern Company, Mississippi Power, and SCS have moved to compel arbitration pursuant to the terms of the CO_2 contract, which the court granted on May 4, 2017. On June 28, 2017, Treetop and other related parties filed a claim for arbitration requesting $500 million in damages.

Southern Company believes these legal challenges have no merit; however, an adverse outcome in these proceedings could have a material impact on Southern Company's results of operations, financial condition, and liquidity. Southern Company will vigorously defend itself in these matters, and the ultimate outcome of these matters cannot be determined at this time.

Nuclear Construction

See Note 3 to the financial statements of Southern Company under "Regulatory Matters – Georgia Power – Nuclear Construction" in Item 8 of the Form 10-K for additional information regarding the construction of Plant Vogtle Units 3 and 4, VCM reports, the NCCR tariff, and the Contractor Settlement Agreement.

Vogtle 3 and 4 Agreement and EPC Contractor Bankruptcy

In 2008, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into the Vogtle 3 and 4 Agreement, pursuant to which the EPC Contractor agreed to design, engineer, procure, construct, and test Plant Vogtle Units 3 and 4. Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Georgia Power's proportionate share of Plant Vogtle Units 3 and 4 is 45.7%.

The Vogtle 3 and 4 Agreement also provided for liquidated damages upon the EPC Contractor's failure to fulfill the schedule and certain performance guarantees, each subject to an aggregate cap of 10% of the contract price, or approximately $920 million (approximately $420 million based on Georgia Power's ownership interest). Under the Toshiba Guarantee, Toshiba guaranteed certain payment obligations of the EPC Contractor, including any liability of the EPC Contractor for abandonment of work. In January 2016, Westinghouse delivered to the Vogtle Owners $920 million of letters of credit from financial institutions (Westinghouse Letters of Credit) to secure a portion of the EPC Contractor's potential obligations under the Vogtle 3 and 4 Agreement. The Westinghouse Letters of Credit are subject to annual renewals through June 30, 2020 and require 60 days' written notice to Georgia Power in the event the Westinghouse Letters of Credit will not be renewed.

Under the terms of the Vogtle 3 and 4 Agreement, the EPC Contractor did not have the right to terminate the Vogtle 3 and 4 Agreement for convenience. In the event of an abandonment of work by the EPC Contractor, the maximum liability of the EPC Contractor under the Vogtle 3 and 4 Agreement was 40% of the contract price (approximately $1.7 billion based on Georgia Power's ownership interest).

On March 29, 2017, the EPC Contractor filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. To provide for a continuation of work at Plant Vogtle Units 3 and 4, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into the Interim Assessment Agreement, which the bankruptcy court approved on March 30, 2017.

The Interim Assessment Agreement provided, among other items, that during the term of the Interim Assessment Agreement (i) Georgia Power was obligated to pay, on behalf of the Vogtle Owners, all costs accrued by the EPC Contractor for subcontractors and vendors for services performed or goods provided, with these amounts paid to the EPC Contractor, except that amounts accrued for Fluor Corporation (Fluor) were paid directly to Fluor; (ii) the EPC Contractor provided certain engineering, procurement, and management services for Plant Vogtle Units 3 and 4, to the same extent as contemplated by the Vogtle 3 and 4 Agreement, and Georgia Power, on behalf of the Vogtle Owners, made payments of $5.4 million per week for these services; (iii) Georgia Power had the right to make payments, on behalf of the Vogtle Owners, directly to subcontractors and vendors who had accounts past due with the EPC Contractor; (iv) the EPC Contractor used commercially reasonable efforts to provide information reasonably requested by Georgia Power as was necessary to continue construction and investigation of the

completion status of Plant Vogtle Units 3 and 4; (v) the EPC Contractor rejected or accepted the Vogtle 3 and 4 Agreement by the termination of the Interim Assessment Agreement; and (vi) Georgia Power did not exercise any remedies against Toshiba under the Toshiba Guarantee. Under the Interim Assessment Agreement, all parties expressly reserved all rights and remedies under the Vogtle 3 and 4 Agreement and all related security and collateral under applicable law.

The Interim Assessment Agreement, as amended, expired on July 27, 2017. Georgia Power's aggregate liability for the Vogtle Owners under the Interim Assessment Agreement totaled approximately $650 million , of which $552 million had been paid or accrued as of June 30, 2017. Georgia Power's proportionate share of this aggregate liability totaled approximately $297 million .

Subsequent to the EPC Contractor bankruptcy filing, a number of subcontractors to the EPC Contractor, including Fluor Enterprises, Inc., a subsidiary of Fluor, alleged non-payment by the EPC Contractor for amounts owed for work performed on Plant Vogtle Units 3 and 4. Georgia Power, acting for itself and as agent for the Vogtle Owners, has taken, and continues to take, actions to remove liens filed by these subcontractors through the posting of surety bonds. Georgia Power estimates the aggregate liability, through July 31, 2017, of the Vogtle Owners for the removal of subcontractor liens and payment of other EPC Contractor pre-petition accounts payable to total approximately $400 million , of which $354 million had been paid or accrued as of June 30, 2017. Georgia Power's proportionate share of this aggregate liability totaled approximately $183 million .

On June 9, 2017, Georgia Power and the other Vogtle Owners and Toshiba entered the Guarantee Settlement Agreement. Pursuant to the Guarantee Settlement Agreement, Toshiba acknowledged the amount of its obligation under the Toshiba Guarantee is $3.68 billion , of which Georgia Power's proportionate share is approximately $1.7 billion, and that the Guarantee Obligations exist regardless of whether Plant Vogtle Units 3 and 4 are completed. The Guarantee Settlement Agreement also provides for a schedule of payments for the Guarantee Obligations, beginning in October 2017 and continuing through January 2021. In the event Toshiba receives certain payments, including sale proceeds, from or related to Westinghouse (or its subsidiaries) or Toshiba Nuclear Energy Holdings (UK) Limited (or its subsidiaries), it will hold a portion of such payments in trust for the Vogtle Owners and promptly pay them as offsets against any remaining Guarantee Obligations. Under the Guarantee Settlement Agreement, the Vogtle Owners will forbear from exercising certain remedies, including drawing on the Westinghouse Letters of Credit, until June 30, 2020, unless certain events of nonpayment, insolvency, or other material breach of the Guarantee Settlement Agreement by Toshiba occur. If such an event occurs, the balance of the Guarantee Obligations will become immediately due and payable, and the Vogtle Owners may exercise any and all rights and remedies, including drawing on the Westinghouse Letters of Credit without restriction. In addition, the Guarantee Settlement Agreement does not restrict the Vogtle Owners from fully drawing on the Westinghouse Letters of Credit in the event they are not renewed or replaced prior to the expiration date.

On June 23, 2017, Toshiba released a revised outlook for fiscal year 2016, which reflected a negative shareholders' equity balance of approximately $5 billion as of March 31, 2017, and announced that its independent audit process was continuing. Toshiba has also announced the existence of material events and conditions that raise substantial doubt about Toshiba's ability to continue as a going concern. As a result, substantial risk regarding the Vogtle Owners' ability to fully collect the Guarantee Obligations continues to exist. An inability or other failure by Toshiba to perform its obligations under the Guarantee Settlement Agreement could have a further material impact on the net cost to the Vogtle Owners to complete construction of Plant Vogtle Units 3 and 4 and, therefore, on Southern Company's financial statements.

Additionally, on June 9, 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the EPC Contractor entered into the Services Agreement, which was amended and restated on July 20, 2017, for the EPC Contractor to transition construction management of Plant Vogtle Units 3 and 4 to Southern Nuclear and to provide ongoing design, engineering, and procurement services to Southern Nuclear. On July 20, 2017, the bankruptcy court approved the EPC Contractor's motion seeking authorization to (i) enter into the Services Agreement, (ii) assume and assign to the Vogtle Owners certain project-related contracts, (iii) join the Vogtle Owners as counterparties to certain assumed project-related contracts, and (iv) reject the Vogtle 3 and 4 Agreement.

The Services Agreement, and the EPC Contractor's rejection of the Vogtle 3 and 4 Agreement, became effective upon approval by the DOE on July 27, 2017. The Services Agreement will continue until the start-up and testing of Plant Vogtle Units 3 and 4 is complete and electricity is generated and sold from both units. The Services Agreement is terminable by the Vogtle Owners upon 30 days' written notice.

The ultimate outcome of these matters cannot be determined at this time.

Regulatory Matters

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4 with a certified capital cost of $4.418 billion . In addition, in 2009 the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows Georgia Power to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff by including the related CWIP accounts in rate base during the construction period. As of June 30, 2017 , Georgia Power had recovered approximately $1.4 billion of financing costs.

On December 20, 2016, the Georgia PSC voted to approve a settlement agreement (Vogtle Cost Settlement Agreement) resolving the following prudence matters: (i) none of the $3.3 billion of costs incurred through December 31, 2015 and reflected in the fourteenth VCM report will be disallowed from rate base on the basis of imprudence; (ii) the Contractor Settlement Agreement is reasonable and prudent and none of the amounts paid or to be paid pursuant to the Contractor Settlement Agreement should be disallowed from rate base on the basis of imprudence; (iii) financing costs on verified and approved capital costs will be deemed prudent provided they are incurred prior to December 31, 2019 and December 31, 2020 for Plant Vogtle Units 3 and 4, respectively; and (iv) (a) the in-service capital cost forecast will be adjusted to $5.680 billion (Revised Forecast), which includes a contingency of $240 million above Georgia Power's then current forecast of $5.440 billion , (b) capital costs incurred up to the Revised Forecast will be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, and (c) Georgia Power would have the burden to show that any capital costs above the Revised Forecast are reasonable and prudent. Under the terms of the Vogtle Cost Settlement Agreement, the certified in-service capital cost for purposes of calculating the NCCR tariff will remain at $4.418 billion . Construction capital costs above $4.418 billion will accrue AFUDC through the date each unit is placed in service. The ROE used to calculate the NCCR tariff was reduced from 10.95% (the ROE rate setting point authorized by the Georgia PSC in the 2013 ARP) to 10.00% effective January 1, 2016. For purposes of the AFUDC calculation, the ROE on costs between $4.418 billion and $5.440 billion will also be 10.00% and the ROE on any amounts above $5.440 billion would be Georgia Power's average cost of long-term debt. If the Georgia PSC adjusts Georgia Power's ROE rate setting point in a rate case prior to Plant Vogtle Units 3 and 4 being placed into retail rate base, then the ROE for purposes of calculating both the NCCR tariff and AFUDC will likewise be 95 basis points lower than the revised ROE rate setting point. If Plant Vogtle Units 3 and 4 are not placed in service by December 31, 2020, then (i) the ROE for purposes of calculating the NCCR tariff will be reduced an additional 300 basis points, or $8 million per month, and may, at the Georgia PSC's discretion, be accrued to be used for the benefit of customers, until such time as the units are placed in service and (ii) the ROE used to calculate AFUDC will be Georgia Power's average cost of long-term debt.

Under the terms of the Vogtle Cost Settlement Agreement, the Georgia PSC will determine, for retail ratemaking purposes, the process of transitioning Plant Vogtle Units 3 and 4 from a construction project to an operating plant no later than Georgia Power's base rate case required to be filed by July 1, 2019.

The Georgia PSC has approved fifteen VCM reports covering the periods through June 30, 2016, including construction capital costs incurred, which through that date totaled $3.7 billion . Georgia Power filed its sixteenth VCM report, covering the period from July 1 through December 31, 2016, requesting approval of $222 million of construction capital costs incurred during that period, with the Georgia PSC on February 27, 2017.

The ultimate outcome of these matters cannot be determined at this time.

Revised Cost and Schedule

Georgia Power and the other Vogtle Owners are continuing to conduct comprehensive schedule and cost-to-complete assessments, as well as cancellation cost assessments, to determine the impact of the EPC Contractor's bankruptcy filing on the construction cost and schedule for Plant Vogtle Units 3 and 4. Georgia Power's preliminary assessment results indicate that its proportionate share of the remaining estimated cost to complete Plant Vogtle Units 3 and 4 ranges as follows:

Preliminary in-service dates					
Unit 3		February 2021	–		March 2022
Unit 4		February 2022	–		March 2023
			(in billions)		
Preliminary estimated cost to complete	$	3.9	–	$	4.6
CWIP as of June 30, 2017		4.5			4.5
Guarantee Obligations		(1.7)			(1.7)
Estimated capital costs	**$**	**6.7**	**–**	**$**	**7.4**
Vogtle Cost Settlement Agreement Revised Forecast		(5.7)			(5.7)
Estimated net additional capital costs	**$**	**1.0**	**–**	**$**	**1.7**

Georgia Power's estimates for cost to complete and schedule are based on preliminary analysis and remain subject to further refinement of labor productivity and consumable and commodity quantities and costs.

Georgia Power's estimated financing costs during the construction period total approximately $3.1 billion to $3.5 billion , of which approximately $1.4 billion had been incurred through June 30, 2017.

Georgia Power's preliminary cancellation cost estimate results indicate that its proportionate share of the estimated cancellation costs is approximately $400 million . As a result, as of June 30, 2017, total estimated costs subject to evaluation by Georgia Power and the Georgia PSC in the event of a cancellation decision are as follows:

		Preliminary Cancellation Cost Estimate
		(in billions)
CWIP as of June 30, 2017	$	4.5
Financing costs collected, net of tax		1.4
Cancellation costs (*)		0.4
Total	**$**	**6.3**

(*) The estimate for cancellation costs includes, but is not limited to, costs to terminate contracts for construction and other services, as well as costs to secure the Plant Vogtle Units 3 and 4 construction site.

The Guarantee Obligations continue to exist in the event of cancellation. In addition, under Georgia law, prudently incurred costs related to certificated projects cancelled by the Georgia PSC are allowed recovery, including carrying costs, in future retail rates. Georgia Power will continue working with the Georgia PSC and the other Vogtle Owners to determine future actions related to Plant Vogtle Units 3 and 4, including, but not limited to, the status of construction and rate recovery, and currently expects to include its recommendation in its seventeenth VCM report to be filed with the Georgia PSC in late August 2017.

The ultimate outcome of these matters is dependent on the completion of the assessments described above, as well as the related regulatory treatment, and cannot be determined at this time.

Other Matters

As of June 30, 2017, Georgia Power had borrowed $2.6 billion related to Plant Vogtle Units 3 and 4 costs through a loan guarantee agreement between Georgia Power and the DOE and a multi-advance credit facility among Georgia Power, the DOE, and the FFB. See Note 6 to the financial statements of Southern Company under "DOE Loan Guarantee Borrowings" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under " DOE Loan Guarantee Borrowings " herein for additional information, including applicable covenants, events of default, mandatory prepayment events, and conditions to borrowing.

The IRS has allocated PTCs to Plant Vogtle Units 3 and 4 which require that the applicable unit be placed in service prior to 2021. The net present value of Georgia Power's PTCs is estimated at approximately $400 million per unit.

There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4 at the federal and state level and additional challenges may arise if construction proceeds. Processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance matters, including the timely resolution of Inspections, Tests, Analyses, and Acceptance Criteria and the related approvals by the NRC, may arise if construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs.

If construction continues, the risk remains that challenges with labor productivity, fabrication, delivery, assembly, and installation of plant systems, structures, and components, or other issues could arise and may further impact project schedule and cost.

The ultimate outcome of these matters cannot be determined at this time.

See RISK FACTORS of Southern Company in Item 1A of the Form 10-K for a discussion of certain risks associated with the licensing, construction, and operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. See additional risks in Item 1A herein regarding the EPC Contractor's bankruptcy.

Income Tax Matters

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Income Tax Matters" of Southern Company in Item 7 of the Form 10-K and Note (G) to the Condensed Financial Statements herein for additional information.

Bonus Depreciation

Approximately $1.2 billion of positive cash flows is expected to result from bonus depreciation for the 2017 tax year, but may not all be realized in 2017 due to net operating loss projections for the 2017 tax year. Approximately $370 million of the 2017 benefit is dependent upon placing the remainder of the Kemper IGCC in service by December 31, 2017. If the suspension of the Kemper IGCC start-up activities results in an abandonment, any amount previously estimated as bonus depreciation would be claimed as a deduction under IRC Section 165. As of June 30, 2017, $82 million has been received through quarterly income tax refunds for bonus depreciation related to the Kemper IGCC, which may be subject to repayment. See Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein and Note (G) to the Condensed Financial Statements herein for additional information. The ultimate outcome of this matter cannot be determined at this time.

Section 174 Research and Experimental Deduction

Southern Company has reflected deductions for research and experimental (R&E) expenditures related to the Kemper IGCC in its federal income tax calculations since 2013 and filed amended federal income tax returns for

2008 through 2013 to also include such deductions. In December 2016, Southern Company and the IRS reached a proposed settlement, subject to approval of the U.S. Congress Joint Committee on Taxation, resolving a methodology for these deductions. Due to the uncertainty related to this tax position, Southern Company had unrecognized tax benefits associated with these R&E deductions totaling approximately $464 million as of June 30, 2017. If the suspension of the Kemper IGCC start-up activities results in an abandonment, any amount not allowed under IRC Section 174 would be claimed as a deduction under IRC Section 165, and would result in a reversal of the related unrecognized tax benefits, excluding interest. See Notes (B) and (G) to the Condensed Financial Statements under " Integrated Coal Gasification Combined Cycle " and "Section 174 Research and Experimental Deduction," respectively, herein for additional information. This matter is expected to be resolved in the next 12 months; however, the ultimate outcome of this matter cannot be determined at this time.

Other Matters

Southern Company and its subsidiaries are involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Southern Company and its subsidiaries are subject to certain claims and legal actions arising in the ordinary course of business. The business activities of Southern Company's subsidiaries are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions , CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation against Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported in Note (B) to the Condensed Financial Statements herein , management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Company's financial statements. See Note (B) to the Condensed Financial Statements herein for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

On January 20, 2017, a purported securities class action complaint was filed against Southern Company, certain of its officers, and certain former Mississippi Power officers in the U.S. District Court for the Northern District of Georgia, Atlanta Division, by Monroe County Employees' Retirement System on behalf of all persons who purchased shares of Southern Company's common stock between April 25, 2012 and October 29, 2013. The complaint alleges that Southern Company, certain of its officers, and certain former Mississippi Power officers made materially false and misleading statements regarding the Kemper IGCC in violation of certain provisions under the Securities Exchange Act of 1934, as amended. The complaint seeks, among other things, compensatory damages and litigation costs and attorneys' fees. On June 12, 2017, the plaintiffs filed an amended complaint that provided additional detail about their claims, increased the purported class period by one day, and added certain other former Mississippi Power officers as defendants. On July 27, 2017, the defendants filed a motion to dismiss the plaintiffs' amended complaint with prejudice.

On February 27, 2017, Jean Vineyard filed a shareholder derivative lawsuit in the U.S. District Court for the Northern District of Georgia that names as defendants Southern Company, certain of its directors, certain of its officers, and certain former Mississippi Power officers. The complaint alleges that the defendants caused Southern Company to make false or misleading statements regarding the Kemper IGCC cost and schedule. Further, the complaint alleges that the defendants were unjustly enriched and caused the waste of corporate assets. The plaintiff seeks to recover, on behalf of Southern Company, unspecified actual damages and, on her own behalf, attorneys' fees and costs in bringing the lawsuit. The plaintiff also seeks certain changes to Southern Company's corporate governance and internal processes. On March 27, 2017, the court deferred this lawsuit until 30 days after certain further action in the purported securities class action complaint discussed above.

On May 15, 2017, Helen E. Piper Survivor's Trust filed a shareholder derivative lawsuit in the Superior Court of Gwinnett County, State of Georgia, that names as defendants Southern Company, certain of its directors, certain of

its officers, and certain former Mississippi Power officers. The complaint alleges that the individual defendants, among other things, breached their fiduciary duties in connection with schedule delays and cost overruns associated with the construction of the Kemper IGCC. The complaint further alleges that the individual defendants authorized or failed to correct false and misleading statements regarding the Kemper IGCC schedule and cost and failed to implement necessary internal controls to prevent harm to Southern Company. The plaintiff seeks to recover, on behalf of Southern Company, unspecified actual damages and disgorgement of profits and, on its behalf, attorneys' fees and costs in bringing the lawsuit. The plaintiff also seeks certain unspecified changes to Southern Company's corporate governance and internal processes.

On June 1, 2017, Judy Mesirov filed a shareholder derivative lawsuit in the U.S. District Court for the Northern District of Georgia, that names as defendants Southern Company, certain of its current and former directors, certain of its officers, and certain former Mississippi Power officers. The complaint alleges that the individual defendants, among other things, breached their fiduciary duties in connection with schedule delays and cost overruns associated with the construction of the Kemper IGCC. The complaint further alleges that the individual defendants authorized or failed to correct false and misleading statements regarding the Kemper IGCC schedule and cost and failed to implement necessary internal controls to prevent harm to Southern Company. The plaintiff seeks to recover, on behalf of Southern Company, unspecified actual damages, disgorgement of profits, and equitable relief and, on her own behalf, attorneys' fees and costs in bringing the lawsuit. The plaintiff also seeks certain unspecified changes to Southern Company's corporate governance and internal processes.

Southern Company believes these legal challenges have no merit; however, an adverse outcome in any of these proceedings could have an impact on Southern Company's results of operations, financial condition, and liquidity. Southern Company will vigorously defend itself in these matters, the ultimate outcome of which cannot be determined at this time.

The SEC is conducting a formal investigation of Southern Company and Mississippi Power concerning the estimated costs and expected in-service date of the Kemper IGCC. Southern Company believes the investigation is focused primarily on periods subsequent to 2010 and on accounting matters, disclosure controls and procedures, and internal controls over financial reporting associated with the Kemper IGCC. See ACCOUNTING POLICIES – " Application of Critical Accounting Policies and Estimates " herein for additional information on the Kemper IGCC. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to have a material impact on the financial statements of Southern Company.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Southern Company prepares its consolidated financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Southern Company in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Southern Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Southern Company in Item 7 of the Form 10-K for a complete discussion of Southern Company's critical accounting policies and estimates related to Utility Regulation, Asset Retirement Obligations, Pension and Other Postretirement Benefits, Goodwill and Other Intangible Assets, Derivatives and Hedging Activities, and Contingent Obligations.

Kemper IGCC Rate Recovery

For periods prior to the second quarter 2017, significant accounting estimates included Kemper IGCC estimated construction costs, project completion date, and rate recovery. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Kemper IGCC Estimated Construction Costs, Project Completion Date, and Rate Recovery" of Southern Company in Item 7 of the Form 10-K for additional information. Mississippi

Power recorded total pre-tax charges to income related to the Kemper IGCC of $428 million ($264 million after tax) in 2016, $365 million ($226 million after tax) in 2015, $868 million ($536 million after tax) in 2014, and $1.2 billion ($729 million after tax) in prior years.

As a result of the Mississippi PSC's June 21, 2017 stated intent to issue an order (which occurred on July 6, 2017) directing Mississippi Power to pursue a settlement under which the Kemper County energy facility would be operated as a natural gas plant rather than an IGCC plant, as well as Mississippi Power's June 28, 2017 suspension of the operation and start-up of the gasifier portion of the Kemper IGCC, the estimated construction costs and project completion date are no longer considered significant accounting estimates. Significant accounting estimates for the June 30, 2017 financial statements presented herein include the overall assessment of rate recovery for the Kemper County energy facility and the estimated costs for the potential cancellation of the Kemper IGCC.

While the ultimate disposition of the gasification portions of the Kemper IGCC remains subject to the Mississippi PSC's jurisdiction, including the potential resolution of the matters addressed in the Kemper Settlement Order, given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility, cost recovery of the gasification portions is no longer probable; therefore, Mississippi Power recorded an additional charge to income in June 2017 of $2.8 billion ($2.0 billion after tax), which includes estimated costs associated with the gasification portions of the plant and lignite mine. In the event the gasification portions of the project are ultimately canceled, additional pre-tax costs currently estimated at approximately $100 million to $200 million are expected to be incurred.

As of June 30, 2017, Mississippi Power has recorded a total of approximately $1.3 billion in costs associated with the combined cycle portion of the Kemper IGCC including transmission and related regulatory assets, of which $0.8 billion is included in retail and wholesale rates. The $0.5 billion not included in current rates includes costs in excess of the original 2010 estimate for the combined cycle portion of the facility, as well as the 15% that was previously contracted to SMEPA. Mississippi Power has calculated the revenue requirements resulting from these remaining costs, using reasonable assumptions for amortization periods, and expects them to be recovered through rates consistent with the Mississippi PSC's requested settlement conditions. The ultimate outcome will be determined by the Mississippi PSC in the Kemper IGCC Settlement Docket proceedings.

In the aggregate, since the Kemper IGCC project started, Mississippi Power has incurred charges of $5.96 billion ($3.94 billion after tax) through June 30, 2017. Mississippi Power recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC of $3.0 billion ($2.1 billion after tax) and $81 million ($50 million after tax) in the second quarter 2017 and the second quarter 2016, respectively, and total pre-tax charges of $3.1 billion ($2.2 billion after tax) and $134 million ($83 million after tax) year-to-date in 2017 and 2016, respectively.

Given the significant judgment involved in estimating the costs to cancel the gasifier portion of the Kemper IGCC, the ultimate rate recovery for the Kemper IGCC, including the $0.5 billion of combined cycle-related costs not yet in rates, and the impact on Southern Company's results of operations, Southern Company considers these items to be critical accounting estimates. See Note 3 to the financial statements of Southern Company under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information.

Recently Issued Accounting Standards

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 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.

While Southern Company expect s most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of all revenue arrangements. The majority of Southern Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity or natural gas without a defined

contractual term, as well as longer-term contractual commitments , including PPAs and non-derivative natural gas asset management and optimization arrangements . Southern Company expect s the adoption of ASC 606 will not result in a significant shift from the current timing of revenue recognition for such transactions .

Southern Company's ongoing evaluation of other revenue streams and related contracts includes unregulated sales to customers. Some revenue arrangements, such as certain PPAs , energy-related derivatives , and alternative revenue programs, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed or presented separately from revenues under ASC 606 on Southern Company's financial statements. In addition, the power and utilities industry continues to evaluate other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). Although final implementation guidance has not been issued, Southern Company expect s CIAC to be out of the scope of ASC 606.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. Southern Company intend s to use the modified retrospective method of adoption effective January 1, 2018. Southern Company has also elected to utilize practical expedients which allow 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, disclosures will include comparative information on 2018 financial statement line items under current guidance. While the adoption of ASC 606, including the cumulative-effect adjustment, is not expected to have a material impact on either the timing or amount of revenues recognized in Southern Company 's financial statements, Southern Company will continue to evaluate the requirements, as well as any additional clarifying guidance that may be issued.

On January 26, 2017, the FASB issued ASU No. 2017-04, *Intangibles – Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment* (ASU 2017-04). ASU 2017-04 removes the requirement to compare the implied fair value of goodwill with the carrying amount as part of Step 2 of the goodwill impairment test. Under the new standard, the goodwill impairment loss will be measured as the excess of a reporting unit's carrying amount over its fair value, not exceeding the total amount of goodwill allocated to that reporting unit, which may increase the frequency of goodwill impairment charges if a future goodwill impairment test does not pass the Step 1 evaluation. ASU 2017-04 is effective prospectively for annual and interim periods beginning on or after December 15, 2019, and early adoption is permitted on testing dates after January 1, 2017.

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 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 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 annual periods beginning after December 15, 2017, including interim periods within those annual periods. Southern Company is currently evaluating the new standard. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in Southern 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 adoption of ASU 2017-07 is not expected to have a material impact on Southern Company's financial statements.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Overview" of Southern Company in Item 7 of the Form 10-K for additional information. Southern Company's financial condition remained stable at June 30, 2017 . Southern Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit agreements to meet future capital and liquidity needs. See " Capital Requirements and Contractual Obligations ," " Sources of Capital ," and " Financing Activities " herein for additional information.

Net cash provided from operating activities totaled $2.7 billion for the first six months of 2017 , an increase of $0.6 billion from the corresponding period in 2016 . The increase in net cash provided from operating activities was primarily due to $1.2 billion of net cash provided from operating activities of Southern Company Gas, which was acquired on July 1, 2016, partially offset by the timing of vendor payments and an increase in under-recovered fuel costs. Net cash used for investing activities totaled $4.9 billion for the first six months of 2017 primarily due to the traditional electric operating companies' installation of equipment to comply with environmental standards and construction of electric generation, transmission, and distribution facilities, capital expenditures for Southern Company Gas' infrastructure replacement programs, and Southern Power's payments for renewable acquisitions. Net cash provided from financing activities totaled $1.6 billion for the first six months of 2017 primarily due to issuances of long-term and short-term debt, partially offset by redemptions of long-term debt and common stock dividend payments. Cash flows from financing activities vary from period to period based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for the first six months of 2017 include an increase of $1.8 billion in property, plant, and equipment in service, net of depreciation primarily related to the traditional electric operating companies' installation of equipment to comply with environmental standards and construction of electric generation, transmission, and distribution facilities, Southern Company Gas' infrastructure replacement programs, and Southern Power's renewable acquisitions; a decrease of $1.5 billion in CWIP primarily related to the estimated probable losses on the Kemper IGCC; a decrease of $0.5 billion in cash and cash equivalents primarily related to acquisition payments at Southern Power; a decrease of $1.4 billion in total common stockholder's equity primarily related to the estimated probable losses on the Kemper IGCC, partially offset by the issuance of additional shares of common stock; an increase of $1.3 billion in long-term debt (excluding amounts due within a year) to fund the Southern Company system's continuous construction programs and for general corporate purposes; and an increase of $1.0 billion in notes payable primarily due to issuances of short-term bank debt for general corporate purposes.

At the end of the second quarter 2017 , the market price of Southern Company's common stock was $47.88 per share (based on the closing price as reported on the New York Stock Exchange) and the book value was $23.38 per share, representing a market-to-book ratio of 205% , compared to $49.19, $25.00, and 197%, respectively, at the end of 2016 . Southern Company's common stock dividend for the second quarter 2017 was $0.58 per share compared to $0.56 per share in the second quarter 2016 .

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company in Item 7 of the Form 10-K for a description of Southern Company's capital requirements for the construction programs of the Southern Company system, including estimated capital expenditures for new electric generating facilities and to comply with existing environmental statutes and regulations, scheduled maturities of long-term debt, as well as related interest, derivative obligations, preferred and preference stock dividends, leases, purchase commitments, pipeline charges, storage capacity, and gas supply, asset management agreements, standby letters of credit and performance/surety bonds, trust funding requirements, and unrecognized tax benefits. Approximately $3.0 billion will be required through June 30, 2018 to fund maturities of long-term debt. See " Sources of Capital " herein for additional information.

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in electric generating plants, including unit retirements and replacements and adding or changing fuel sources at existing electric generating units, to meet regulatory requirements; changes in FERC rules and regulations; state regulatory agency approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. Additionally, planned expenditures for plant acquisitions may vary due to market opportunities and Southern Power's ability to execute its growth strategy. See Note 12 to the financial statements of Southern Company under "Southern Power" in Item 8 of the Form 10-K and Note (I) to the Condensed Financial Statements under " Southern Power " herein for additional information regarding Southern Power's plant acquisitions. See Note 3 to the financial statements of Southern Company under "Regulatory Matters – Georgia Power – Nuclear Construction" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under " Regulatory Matters – Georgia Power – Nuclear Construction " herein for information regarding additional factors that may impact construction expenditures, including Georgia Power's preliminary cost-to-complete and cancellation cost assessments for Plant Vogtle Units 3 and 4.

Sources of Capital

Southern Company intends to meet its future capital needs through operating cash flows, short-term debt, term loans, and external security issuances. Equity capital can be provided from any combination of Southern Company's stock plans, private placements, or public offerings. The amount and timing of additional equity capital and debt issuances in 2017 , as well as in subsequent years, will be contingent on Southern Company's investment opportunities and the Southern Company system's capital requirements and will depend upon prevailing market conditions and other factors. See " Capital Requirements and Contractual Obligations " herein for additional information.

Except as described herein, the traditional electric operating companies, Southern Power, and Southern Company Gas plan to obtain the funds required for construction and other purposes from operating cash flows, external security issuances, term loans, short-term borrowings, and equity contributions or loans from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Southern Company in Item 7 of the Form 10-K for additional information.

In addition, Georgia Power has entered into a loan guarantee agreement (Loan Guarantee Agreement) with the DOE, under which the proceeds of borrowings may be used to reimburse Georgia Power for Eligible Project Costs incurred in connection with its construction of Plant Vogtle Units 3 and 4. Under the Loan Guarantee Agreement, the DOE agreed to guarantee borrowings of up to $3.46 billion (not to exceed 70% of Eligible Project Costs) to be made by Georgia Power under a multi-advance credit facility (FFB Credit Facility) among Georgia Power, the DOE, and the FFB. Eligible Project Costs incurred through June 30, 2017 would allow for borrowings of up to $3.1 billion under the FFB Credit Facility, of which Georgia Power has borrowed $2.6 billion ; however, on July 27, 2017, Georgia Power entered into an amendment to the Loan Guarantee Agreement (LGA Amendment) to clarify the operation of the Loan Guarantee Agreement pending Georgia Power's completion of its comprehensive schedule, cost-to-complete, and cancellation cost assessments (Cost Assessments) for Plant Vogtle Units 3 and 4. Under the terms of the LGA Amendment, Georgia Power will not request any advances under the Loan Guarantee Agreement unless and until such time as Georgia Power has completed the Cost Assessments and made a determination to continue construction of Plant Vogtle Units 3 and 4 and satisfied certain other conditions related to continuing construction. See Note 6 to the financial statements of Southern Company under "DOE Loan Guarantee Borrowings" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under " DOE Loan Guarantee Borrowings " herein for additional information regarding the Loan Guarantee Agreement, including applicable covenants, events of default, mandatory prepayment events, and additional conditions to borrowing. Also

see Note (B) to the Condensed Financial Statements under " Regulatory Matters – Georgia Power – Nuclear Construction " herein for additional information regarding Plant Vogtle Units 3 and 4.

As of June 30, 2017 , Southern Company's current liabilities exceeded current assets by $3.9 billion due to notes payable of $3.3 billion (comprised of approximately $0.9 billion at the parent company, $1.2 billion at Georgia Power, $0.1 billion at Gulf Power, $0.4 billion at Southern Power, and $0.6 billion at Southern Company Gas) and long-term debt that is due within one year of $3.0 billion (comprised of approximately $0.4 billion at the parent company, $0.4 billion at Alabama Power, $0.3 billion at Georgia Power, $1.0 billion at Mississippi Power, and $0.9 billion at Southern Power). To meet short-term cash needs and contingencies, the Southern Company system has substantial cash flow from operating activities and access to capital markets and financial institutions. Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas intend to utilize operating cash flows, as well as commercial paper, lines of credit, bank notes, and securities issuances, as market conditions permit, as well as, under certain circumstances for the traditional electric operating companies, Southern Power, and Southern Company Gas, equity contributions and/or loans from Southern Company to meet their short-term capital needs.

At June 30, 2017 , Southern Company and its subsidiaries had approximately $1.4 billion of cash and cash equivalents. Committed credit arrangements with banks at June 30, 2017 were as follows:

	Expires							Executable Term Loans		Expires Within One Year	
Company	**2017**	**2018**	**2019**	**2020**	**2022**	**Total**	**Unused**	**One Year**	**Two Years**	**Term Out**	**No Term Out**
							(in millions)				
Southern Company [(a)]	$ —	$ —	$ —	$ —	$ 2,000	$ 2,000	$ 2,000	$ —	$ —	$ —	$ —
Alabama Power	3	532	—	—	800	1,335	1,335	—	—	—	35
Georgia Power	—	—	—	—	1,750	1,750	1,732	—	—	—	—
Gulf Power	30	195	25	30	—	280	280	45	—	—	40
Mississippi Power	113	—	—	—	—	113	100	—	13	13	100
Southern Power Company	—	—	—	—	750	750	675	—	—	—	—
Southern Company Gas [(b)]	—	—	—	—	1,900	1,900	1,849	—	—	—	—
Other	10	30	—	—	—	40	40	20	—	20	20
Southern Company Consolidated	$ 156	$ 757	$ 25	$ 30	$ 7,200	$ 8,168	$ 8,011	$ 65	$ 13	$ 33	$ 195

(a) Represents the Southern Company parent entity.

(b) Southern Company Gas, as the parent entity, guarantees the obligations of Southern Company Gas Capital, which is the borrower of $1.2 billion of these arrangements. Southern Company Gas' committed credit arrangements also include $700 million for which Nicor Gas is the borrower and which is restricted for working capital needs of Nicor Gas.

See Note 6 to the financial statements of Southern Company under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under " Bank Credit Arrangements " herein for additional information.

As reflected in the table above, in May 2017, Southern Company, Alabama Power, Georgia Power, and Southern Power Company each amended certain of their multi-year credit arrangements, which, among other things, extended the maturity dates from 2020 to 2022. Southern Company and Southern Power Company increased their borrowing ability under these arrangements to $2.0 billion from $1.25 billion and to $750 million from $600 million, respectively. Southern Company also terminated its $1.0 billion facility maturing in 2018. Also in May 2017, Southern Company Gas Capital and Nicor Gas terminated their existing credit arrangements for $1.3 billion and $700 million , respectively, which were to mature in 2017 and 2018, and entered into a new multi-year credit arrangement currently allocated for $1.2 billion and $700 million, respectively, with a maturity date of 2022.

Most of these bank credit arrangements, as well as the term loan arrangements of Southern Company, Alabama Power, Georgia Power, Mississippi Power, and Southern Power Company, contain covenants that limit debt levels and contain cross-acceleration or cross-default provisions to other indebtedness (including guarantee obligations) that are restricted only to the indebtedness of the individual company. Such cross-default provisions to other indebtedness would trigger an event of default if the applicable borrower defaulted on indebtedness or guarantee obligations over a specified threshold. Such cross-acceleration provisions to other indebtedness would trigger an event of default if the applicable borrower defaulted on indebtedness, the payment of which was then accelerated. At June 30, 2017 , Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas were in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

Subject to applicable market conditions, Southern Company and its subsidiaries expect to renew or replace their bank credit arrangements as needed, prior to expiration. In connection therewith, Southern Company and its subsidiaries may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

A portion of the unused credit with banks is allocated to provide liquidity support to the pollution control revenue bonds of the traditional electric operating companies and the commercial paper programs of Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas. The amount of variable rate pollution control revenue bonds of the traditional electric operating companies outstanding requiring liquidity support as of June 30, 2017 was approximately $1.6 billion . In June 2017, Georgia Power remarketed $318 million of variable rate pollution control bonds in index rate modes, reducing the liquidity support utilized under Georgia Power's bank credit arrangement. In addition, at June 30, 2017 , the traditional electric operating companies had approximately $626 million of pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

Southern Company, the traditional electric operating companies (other than Mississippi Power), Southern Power Company, Southern Company Gas, and Nicor Gas make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. Short-term borrowings are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Short-term Debt at June 30, 2017		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)*
Commercial paper	$ 2,257	1.5%	$ 2,519	1.3%	$ 2,946
Short-term bank debt	1,017	2.0%	321	2.0%	1,017
Total	$ 3,274	1.7%	$ 2,840	1.4%	

(*) Average and maximum amounts are based upon daily balances during the three -month period ended June 30, 2017 .

Southern Company believes the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, bank term loans, and operating cash flows.

Credit Rating Risk

At June 30, 2017 , Southern Company and its subsidiaries 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 of certain subsidiaries to BBB and/or Baa2 or below. These contracts are for physical electricity and natural gas purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management,

transmission, interest rate management, and foreign currency risk management, and, at June 30, 2017 , included contracts related to the construction of new generation at Plant Vogtle Units 3 and 4.

The maximum potential collateral requirements under these contracts at June 30, 2017 were as follows:

Credit Ratings		Maximum Potential Collateral Requirements
		(in millions)
At BBB and/or Baa2	$	39
At BBB- and/or Baa3	$	642
At BB+ and/or Ba1 (*)	$	2,555

(*) Any additional credit rating downgrades at or below BB- and/or Ba3 could increase collateral requirements up to an additional $38 million.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of Southern Company and its subsidiaries to access capital markets, and would be likely to impact the cost at which they do so.

On March 1, 2017, Moody's downgraded the senior unsecured debt rating of Mississippi Power to Ba1 from Baa3.

On March 20, 2017, Moody's revised its rating outlook for Georgia Power from stable to negative.

On March 24, 2017, S&P revised its consolidated credit rating outlook for Southern Company and its subsidiaries (including the traditional electric operating companies, Southern Power, Southern Company Gas, Southern Company Gas Capital, and Nicor Gas) from stable to negative.

On March 30, 2017, Fitch placed the ratings of Southern Company, Georgia Power, and Mississippi Power on rating watch negative.

On June 22, 2017, Moody's placed the ratings of Mississippi Power on review for downgrade.

Financing Activities

During the first six months of 2017 , Southern Company issued approximately 7.8 million shares of common stock primarily through employee equity compensation plans and received proceeds of approximately $352 million.

In addition, during the second quarter 2017, Southern Company issued approximately 1.3 million shares of common stock through at-the-market issuances pursuant to sales agency agreements related to Southern Company's continuous equity offering program and received cash proceeds of approximately $65 million, net of $553,000 in fees and commissions.

The following table outlines the long-term debt financing activities for Southern Company and its subsidiaries for the first six months of 2017 :

Company	Senior Note Issuances	Senior Note Maturities and Redemptions	Revenue Bond Maturities, Redemptions, and Repurchases	Other Long-Term Debt Issuances	Other Long-Term Debt Redemptions and Maturities [a]
			(in millions)		
Southern Company [b]	$ 300	$ —	$ —	$ 500	$ 400
Alabama Power	550	200	—	—	—
Georgia Power	850	450	27	—	3
Gulf Power	300	85	—	6	—
Mississippi Power	—	—	—	40	893
Southern Power	—	—	—	3	3
Southern Company Gas [c]	450	—	—	—	—
Other	—	—	—	—	8
Elimination [d]	—	—	—	(40)	(591)
Southern Company Consolidated	$ 2,450	$ 735	$ 27	$ 509	$ 716

(a) Includes reductions in capital lease obligations resulting from cash payments under capital leases.

(b) Represents the Southern Company parent entity.

(c) The senior notes were issued by Southern Company Gas Capital and guaranteed by the Southern Company Gas parent entity.

(d) Intercompany loans from Southern Company to Mississippi Power eliminated in Southern Company's Consolidated Financial Statements.

In March 2017, Southern Company repaid at maturity a $400 million 18-month floating rate bank loan.

In June 2017, Southern Company issued $500 million aggregate principal amount of Series 2017A 5.325% Junior Subordinated Notes due June 21, 2057. The proceeds were used to repay short-term indebtedness and for other general corporate purposes.

Also in June 2017, Southern Company issued $300 million aggregate principal amount of Series 2017A Floating Rate Senior Notes due September 30, 2020, which bear interest at a floating rate based on three-month LIBOR. The proceeds were used to repay short-term indebtedness and for other general corporate purposes.

Also in June 2017, Southern Company entered into two $100 million aggregate principal amount floating rate bank term loan agreements, which mature on June 21, 2018 and June 29, 2018 and bear interest based on one-month LIBOR. The proceeds were used for working capital and other general corporate purposes.

Except as described herein, Southern Company's subsidiaries used the proceeds of the debt issuances shown in the table above for their redemptions and maturities shown in the table above, to repay short-term indebtedness, and for general corporate purposes, including their continuous construction programs.

A portion of the proceeds of Gulf Power's senior note issuances was used in June 2017 to redeem 550,000 shares ($55 million aggregate liquidation amount) of Gulf Power's 6.00% Series Preference Stock, 450,000 shares ($45 million aggregate liquidation amount) of Gulf Power's Series 2007A 6.45% Preference Stock, and 500,000 shares ($50 million aggregate liquidation amount) of Gulf Power's Series 2013A 5.60% Preference Stock.

In March 2017, Gulf Power extended the maturity of a $100 million short-term floating rate bank loan bearing interest based on one-month LIBOR from April 2017 to October 2017 and subsequently repaid the loan in May 2017.

In June 2017, Georgia Power entered into three floating rate bank loans in aggregate principal amounts of $50 million, $150 million, and $100 million, which mature on December 1, 2017, May 31, 2018, and June 28, 2018,

respectively, and bear interest based on one-month LIBOR. Also in June 2017, Georgia Power borrowed $500 million pursuant to an uncommitted bank credit arrangement, which bears interest at a rate agreed upon by Georgia Power and the bank from time to time and is payable on no less than 30 days' demand by the bank. The proceeds from these bank loans were used to repay a portion of Georgia Power's existing indebtedness and for working capital and other general corporate purposes, including Georgia Power's continuous construction program.

In June 2017, Mississippi Power prepaid $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan, which matures on March 30, 2018.

Subsequent to June 30, 2017, Nicor Gas agreed to issue $400 million aggregate principal amount of First Mortgage Bonds in a private placement, $200 million of which is expected to be issued in each of August 2017 and November 2017.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Southern Company and its subsidiaries plan to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

PART I

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

During the six months ended June 30, 2017 , there were no material changes to Southern Company's, Alabama Power's, Georgia Power's, Mississippi Power's, and Southern Power's disclosures about market risk. For additional market risk disclosures relating to Gulf Power and Southern Company Gas, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of Gulf Power and Southern Company Gas, respectively, herein. For an in-depth discussion of each registrant's market risks, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of each registrant in Item 7 of the Form 10-K and Note 1 to the financial statements of each registrant under "Financial Instruments," Note 11 to the financial statements of Southern Company, Alabama Power, and Georgia Power, Note 10 to the financial statements of Gulf Power, Mississippi Power, and Southern Company Gas, and Note 9 to the financial statements of Southern Power in Item 8 of the Form 10-K. Also see Note (C) and Note (H) to the Condensed Financial Statements herein for information relating to derivative instruments.

Item 4. Controls and Procedures.

(a) Evaluation of disclosure controls and procedures.

As of the end of the period covered by this Quarterly Report on Form 10-Q, Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and Southern Company Gas conducted separate evaluations under the supervision and with the participation of each company's management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as defined in Sections 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended). Based upon these evaluations, the Chief Executive Officer and the Chief Financial Officer, in each case, concluded that the disclosure controls and procedures are effective.

(b) Changes in internal controls over financial reporting.

There have been no changes in Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, Southern Power's, or Southern Company Gas' internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended) during the second quarter 2017 that have materially affected or are reasonably likely to materially affect Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, Southern Power's, or Southern Company Gas' internal control over financial reporting.

ALABAMA POWER COMPANY

ALABAMA POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	**2017**	2016
	(in millions)		*(in millions)*	
Operating Revenues:				
Retail revenues	**$ 1,333**	$ 1,316	**$ 2,560**	$ 2,510
Wholesale revenues, non-affiliates	**68**	67	**133**	130
Wholesale revenues, affiliates	**32**	9	**65**	31
Other revenues	**51**	52	**108**	105
Total operating revenues	**1,484**	1,444	**2,866**	2,776
Operating Expenses:				
Fuel	**303**	295	**601**	564
Purchased power, non-affiliates	**40**	40	**75**	76
Purchased power, affiliates	**34**	55	**62**	88
Other operations and maintenance	**375**	355	**743**	747
Depreciation and amortization	**183**	175	**364**	347
Taxes other than income taxes	**95**	94	**191**	191
Total operating expenses	**1,030**	1,014	**2,036**	2,013
Operating Income	**454**	430	**830**	763
Other Income and (Expense):				
Allowance for equity funds used during construction	**8**	6	**16**	16
Interest expense, net of amounts capitalized	**(77)**	(74)	**(153)**	(147)
Other income (expense), net	**1**	(4)	**(4)**	(11)
Total other income and (expense)	**(68)**	(72)	**(141)**	(142)
Earnings Before Income Taxes	**386**	358	**689**	621
Income taxes	**151**	140	**277**	242
Net Income	**235**	218	**412**	379
Dividends on Preferred and Preference Stock	**5**	5	**9**	9
Net Income After Dividends on Preferred and Preference Stock	**$ 230**	$ 213	**$ 403**	$ 370

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	**2017**	2016
	(in millions)		*(in millions)*	
Net Income	**$ 235**	$ 218	**$ 412**	$ 379
Other comprehensive income (loss):				
Qualifying hedges:				
Changes in fair value, net of tax of $-, $-, $-, and $(1), respectively	**—**	—	**—**	(2)
Reclassification adjustment for amounts included in net income, net of tax of $1, $-, $1, and $1, respectively	**1**	1	**2**	2
Total other comprehensive income (loss)	**1**	1	**2**	—
Comprehensive Income	**$ 236**	$ 219	**$ 414**	$ 379

The accompanying notes as they relate to Alabama Power are an integral part of these condensed financial statements.

ALABAMA POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Six Months Ended June 30,	
	2017	2016
	(in millions)	
Operating Activities:		
Net income	**$ 412**	$ 379
Adjustments to reconcile net income to net cash provided from operating activities —		
Depreciation and amortization, total	**442**	419
Deferred income taxes	**192**	175
Pension, postretirement, and other employee benefits	**(24)**	(23)
Other, net	**4**	(33)
Changes in certain current assets and liabilities —		
-Receivables	**(58)**	64
-Fossil fuel stock	**13**	(32)
-Other current assets	**(75)**	(67)
-Accounts payable	**(154)**	(75)
-Accrued taxes	**52**	102
-Accrued compensation	**(74)**	(50)
-Retail fuel cost over recovery	**(65)**	(60)
-Other current liabilities	**7**	8
Net cash provided from operating activities	**672**	807
Investing Activities:		
Property additions	**(738)**	(645)
Nuclear decommissioning trust fund purchases	**(117)**	(200)
Nuclear decommissioning trust fund sales	**117**	200
Cost of removal, net of salvage	**(54)**	(51)
Change in construction payables	**48**	(27)
Other investing activities	**(15)**	(18)
Net cash used for investing activities	**(759)**	(741)
Financing Activities:		
Proceeds —		
Senior notes	**550**	400
Capital contributions from parent company	**327**	237
Other long-term debt	**—**	45
Redemptions — Senior notes	**(200)**	(200)
Payment of common stock dividends	**(357)**	(382)
Other financing activities	**(14)**	(17)
Net cash provided from financing activities	**306**	83
Net Change in Cash and Cash Equivalents	**219**	149
Cash and Cash Equivalents at Beginning of Period	**420**	194
Cash and Cash Equivalents at End of Period	**$ 639**	$ 343
Supplemental Cash Flow Information:		
Cash paid (received) during the period for —		
Interest (net of $6 and $7 capitalized for 2017 and 2016, respectively)	**$ 140**	$ 131
Income taxes, net	**88**	(122)
Noncash transactions — Accrued property additions at end of period	**132**	94

The accompanying notes as they relate to Alabama Power are an integral part of these condensed financial statements.

ALABAMA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Assets	**At June 30, 2017**	At December 31, 2016
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 639**	$ 420
Receivables —		
Customer accounts receivable	**357**	348
Unbilled revenues	**161**	146
Other accounts and notes receivable	**36**	27
Affiliated	**33**	40
Accumulated provision for uncollectible accounts	**(9)**	(10)
Fossil fuel stock	**191**	205
Materials and supplies	**443**	435
Prepaid expenses	**86**	34
Other regulatory assets, current	**135**	149
Other current assets	**7**	11
Total current assets	**2,079**	1,805
Property, Plant, and Equipment:		
In service	**26,466**	26,031
Less: Accumulated provision for depreciation	**9,354**	9,112
Plant in service, net of depreciation	**17,112**	16,919
Nuclear fuel, at amortized cost	**333**	336
Construction work in progress	**668**	491
Total property, plant, and equipment	**18,113**	17,746
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**67**	66
Nuclear decommissioning trusts, at fair value	**848**	792
Miscellaneous property and investments	**119**	112
Total other property and investments	**1,034**	970
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**526**	525
Deferred under recovered regulatory clause revenues	**6**	150
Other regulatory assets, deferred	**1,209**	1,157
Other deferred charges and assets	**166**	163
Total deferred charges and other assets	**1,907**	1,995
Total Assets	**$ 23,133**	$ 22,516

The accompanying notes as they relate to Alabama Power are an integral part of these condensed financial statements.

ALABAMA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	At June 30, 2017	At December 31, 2016
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 361**	$ 561
Accounts payable —		
Affiliated	**242**	297
Other	**317**	433
Customer deposits	**91**	88
Accrued taxes —		
Accrued income taxes	**39**	45
Other accrued taxes	**97**	42
Accrued interest	**81**	78
Accrued compensation	**125**	193
Other regulatory liabilities, current	**15**	85
Other current liabilities	**63**	76
Total current liabilities	**1,431**	1,898
Long-term Debt	**7,082**	6,535
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**4,842**	4,654
Deferred credits related to income taxes	**64**	65
Accumulated deferred ITCs	**113**	110
Employee benefit obligations	**269**	300
Asset retirement obligations	**1,543**	1,503
Other cost of removal obligations	**648**	684
Other regulatory liabilities, deferred	**84**	100
Other deferred credits and liabilities	**69**	63
Total deferred credits and other liabilities	**7,632**	7,479
Total Liabilities	**16,145**	15,912
Redeemable Preferred Stock	**85**	85
Preference Stock	**196**	196
Common Stockholder's Equity:		
Common stock, par value $40 per share —		
Authorized — 40,000,000 shares		
Outstanding — 30,537,500 shares	**1,222**	1,222
Paid-in capital	**2,950**	2,613
Retained earnings	**2,564**	2,518
Accumulated other comprehensive loss	**(29)**	(30)
Total common stockholder's equity	**6,707**	6,323
Total Liabilities and Stockholder's Equity	**$ 23,133**	$ 22,516

The accompanying notes as they relate to Alabama Power are an integral part of these condensed financial statements.

ALABAMA POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

SECOND QUARTER 2017 vs. SECOND QUARTER 2016
AND
YEAR-TO-DATE 2017 vs. YEAR-TO-DATE 2016

OVERVIEW

Alabama Power 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 Alabama Power's business of providing electric service. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, stringent environmental standards, reliability, fuel, capital expenditures, and restoration following major storms. Alabama Power 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 Alabama Power for the foreseeable future.

Alabama Power 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.

RESULTS OF OPERATIONS

Net Income

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$17	8.0	$33	8.9

Alabama Power's net income after dividends on preferred and preference stock for the second quarter 2017 was $230 million compared to $213 million for the corresponding period in 2016 . The increase was primarily related to an increase in rates under Rate RSE effective January 1, 2017 and an increase in other income (expense), net. These increases were partially offset by an increase in operations and maintenance expenses and a decrease in retail revenues associated with milder weather and lower customer usage in the second quarter 2017 compared to the corresponding period in 2016 .

Alabama Power's net income after dividends on preferred and preference stock for year-to-date 2017 was $403 million compared to $370 million for the corresponding period in 2016 . The increase was primarily related to an increase in rates under Rate RSE effective January 1, 2017, partially offset by a decrease in retail revenues associated with milder weather for year-to-date 2017 compared to the corresponding period in 2016.

Retail Revenues

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$17	1.3	$50	2.0

In the second quarter 2017 , retail revenues were $1.33 billion compared to $1.32 billion for the corresponding period in 2016 . For year-to-date 2017 , retail revenues were $2.56 billion compared to $2.51 billion for the corresponding period in 2016 .

Details of the changes in retail revenues were as follows:

	Second Quarter 2017		Year-to-Date 2017	
	(in millions)	*(% change)*	*(in millions)*	*(% change)*
Retail – prior year	$ 1,316		$ 2,510	
Estimated change resulting from –				
Rates and pricing	75	5.7	154	6.2
Sales decline	(11)	(0.8)	(12)	(0.5)
Weather	(11)	(0.8)	(66)	(2.6)
Fuel and other cost recovery	(36)	(2.8)	(26)	(1.1)
Retail – current year	$ 1,333	1.3%	$ 2,560	2.0%

Revenues associated with changes in rates and pricing increased in the second quarter and year-to-date 2017 when compared to the corresponding periods in 2016 primarily due to an increase in rates under Rate RSE effective January 1, 2017. See Note 3 to the financial statements of Alabama Power under "Retail Regulatory Matters" in Item 8 of the Form 10-K for additional information.

Revenues attributable to changes in sales decreased in the second quarter and year-to-date 2017 when compared to the corresponding periods in 2016 . Weather-adjusted residential KWH sales decreased 1.1% and 0.2% for the second quarter and year-to-date 2017 , respectively, primarily due to lower customer usage resulting from an increase in efficiency improvements in residential appliances and lighting, partially offset by customer growth. Weather-adjusted commercial KWH sales decreased 0.4% and 0.8% for the second quarter and year-to-date 2017 , respectively, primarily due to lower customer usage. Industrial KWH sales increased 1.0% for the second quarter 2017 when compared to the corresponding period in 2016 as a result of an increase in demand resulting from changes in production levels primarily in the chemicals and mining sectors, partially offset by a decrease in demand from the paper, primary metals, pipelines, and lumber sectors. Industrial KWH sales remained flat year-to-date 2017 when compared to the corresponding period in 2016 as a result of an increase in demand resulting from changes in production levels primarily in the chemicals and mining sectors, offset by a decrease in demand from the pipelines, lumber, and stone, clay, and glass sectors.

Revenues resulting from changes in weather decreased in the second quarter and year-to-date 2017 due to milder weather experienced in Alabama Power's service territory compared to the corresponding periods in 2016 . For the second quarter 2017 , the resulting decreases were 1.5% and 0.7% for residential and commercial sales revenues, respectively. For year-to-date 2017 , the resulting decreases were 5.2% and 1.4% for residential and commercial sales revenues, respectively.

Fuel and other cost recovery revenues decreased in the second quarter 2017 and year-to-date 2017 when compared to the corresponding periods in 2016 primarily due to an increase in wholesale revenues to affiliates, which offsets retail fuel cost recovery. Electric rates include provisions to recognize the full recovery of fuel costs, purchased power costs, PPAs certificated by the Alabama PSC, and costs associated with the natural disaster reserve. Under these provisions, fuel and other cost recovery revenues generally equal fuel and other cost recovery expenses and do not affect net income. See Note 3 to the financial statements of Alabama Power under "Retail Regulatory Matters" in Item 8 of the Form 10-K for additional information.

Wholesale Revenues – Affiliates

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$23	255.6	$34	109.7

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the 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 Alabama Power's energy cost recovery clauses.

In the second quarter 2017 , wholesale revenues from sales to affiliates were $32 million compared to $9 million for the corresponding period in 2016 . The increase was primarily due to a 175.0% increase in KWH sales as a result of lower cost Alabama Power-owned generation available to the Southern Company system and a 29.3% increase in the price of energy due to an increase in natural gas prices. For year-to-date 2017 , wholesale revenues from sales to affiliates were $65 million compared to $31 million for the corresponding period in 2016 . The increase was primarily due to an 83.5% increase in KWH sales as a result of supporting Southern Company system transmission reliability and a 15.5% increase in the price of energy due to an increase in natural gas prices.

Fuel and Purchased Power Expenses

	Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
	(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
Fuel	$ 8	2.7	$ 37	6.6
Purchased power – non-affiliates	—	—	(1)	(1.3)
Purchased power – affiliates	(21)	(38.2)	(26)	(29.5)
Total fuel and purchased power expenses	$ (13)		$ 10	

In the second quarter 2017 , fuel and purchased power expenses were $377 million compared to $390 million for the corresponding period in 2016 . The decrease was primarily due to a $55 million decrease in the volume of KWHs purchased. This decrease was partially offset by a $24 million net increase related to the average cost of purchased power and fuel and an $18 million increase related to the volume of KWHs generated.

For year-to-date 2017 , fuel and purchased power expenses were $738 million compared to $728 million for the corresponding period in 2016 . The increase was primarily due to a $58 million increase in the volume of KWHs generated and a $31 million net increase related to the average cost of purchased power and fuel. These increases were partially offset by a $79 million decrease in 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 Alabama Power's energy cost recovery clause. See Note 3 to the financial statements of Alabama Power under "Retail Regulatory Matters – Rate ECR" in Item 8 of the Form 10-K for additional information.

Details of Alabama Power's generation and purchased power were as follows:

	Second Quarter 2017	Second Quarter 2016	**Year-to-Date 2017**	Year-to-Date 2016
Total generation *(in billions of KWHs)*	**15**	13	**30**	28
Total purchased power *(in billions of KWHs)*	**1**	3	**2**	4
Sources of generation *(percent)* —				
Coal	**47**	53	**48**	46
Nuclear	**25**	23	**26**	25
Gas	**20**	20	**20**	19
Hydro	**8**	4	**6**	10
Cost of fuel, generated *(in cents per net KWH)* —				
Coal	**2.63**	2.84	**2.61**	2.85
Nuclear	**0.76**	0.79	**0.75**	0.78
Gas	**2.75**	2.52	**2.76**	2.49
Average cost of fuel, generated *(in cents per net KWH)* (a)	**2.14**	2.28	**2.13**	2.20
Average cost of purchased power *(in cents per net KWH)* (b)	**7.11**	3.94	**6.92**	4.37

(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 Alabama Power for tolling agreements where power is generated by the provider.

Fuel

For year-to-date 2017 , fuel expense was $601 million compared to $564 million for the corresponding period in 2016 . The increase was primarily due to increases of 11.0% and 8.4% in the volume of KWHs generated by coal and natural gas, respectively, a 10.8% increase in the average cost of natural gas per KWH generated, which excludes fuel associated with tolling agreements, and a 28.1% decrease in the volume of KWHs generated by hydro facilities. The increase was partially offset by an 8.4% decrease in the average cost of coal per KWH generated.

Purchased Power – Affiliates

In the second quarter 2017 , purchased power expense from affiliates was $34 million compared to $55 million for the corresponding period in 2016 . The decrease was primarily related to a 61.1% decrease in the amount of energy purchased as a result of lower cost Alabama Power-owned generation, partially offset by a 60.3% increase in the average cost of purchased power per KWH as a result of higher natural gas prices.

For year-to-date 2017 , purchased power expense from affiliates was $62 million compared to $88 million for the corresponding period in 2016 . The decrease was primarily related to a 56.1% decrease in the amount of energy purchased due to an increase in generation as a result of supporting Southern Company system transmission reliability, partially offset by a 60.0% increase in the average cost of purchased power per KWH as a result of higher natural gas prices.

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

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$20	5.6	$(4)	(0.5)

In the second quarter 2017 , other operations and maintenance expenses were $375 million compared to $355 million for the corresponding period in 2016 . The increase was primarily due to increases of $13 million in vegetation management costs, $7 million in nuclear generation plant improvement costs, and $3 million in employee benefit costs. The increase was partially offset by a $4 million decrease in scheduled other power generation outage costs.

Depreciation and Amortization

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$8	4.6	$17	4.9

In the second quarter 2017 , depreciation and amortization was $183 million compared to $175 million for the corresponding period in 2016 . For year-to-date 2017 , depreciation and amortization was $364 million compared to $347 million for the corresponding period in 2016 . These increases were primarily due to additional plant in service related to distribution, steam generation, and transmission assets. In addition, there was an increase in depreciation rates, effective January 1, 2017, associated with compliance-related steam projects, asset retirement obligation recovery, and other generation assets, partially offset by a decrease in distribution-related rates. See Note 1 to the financial statements of Alabama Power under "Depreciation and Amortization" in Item 8 of the Form 10-K for additional information.

Other Income (Expense), Net

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$5	125.0	$7	63.6

In the second quarter 2017 , other income (expense), net was $1 million compared to $(4) million for the corresponding period in 2016 . For year-to-date 2017 , other income (expense), net was $(4) million compared to $(11) million for the corresponding period in 2016 . The changes were primarily due to decreases in donations and increases in sales of non-utility property and unregulated lighting services in 2017.

Income Taxes

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$11	7.9	$35	14.5

In the second quarter 2017 , income taxes were $151 million compared to $140 million for the corresponding period in 2016 . The increase was primarily due to higher pre-tax earnings.

For year-to-date 2017 , income taxes were $277 million compared to $242 million for the corresponding period in 2016 . The increase was primarily due to higher pre-tax earnings and unrecognized tax benefits related to certain state deductions for federal income taxes.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Alabama Power's future earnings potential. The level of Alabama Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Alabama Power's primary business of providing electric service. These factors include Alabama Power'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 driven primarily by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies and increasing volumes of electronic commerce transactions. Earnings are subject to a variety of other factors. These factors include weather, competition, 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 Alabama Power's service territory. Demand for electricity is primarily driven by economic growth. The pace of economic growth and electricity demand may be affected by changes in regional and global economic conditions, which may impact future earnings. Current proposals related to potential federal tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals is dependent on the final form of any legislation enacted and the related transition rules and cannot be determined at this time, but could have a material impact on Alabama Power's financial statements. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Alabama Power in Item 7 of the Form 10-K.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are completed. Environmental compliance costs are recovered through Rate CNP Compliance. See Note 3 to the financial statements of Alabama Power under "Retail Regulatory Matters – Rate CNP Compliance" in Item 8 of the Form 10-K for additional information. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Alabama Power in Item 7 and Note 3 to the financial statements of Alabama Power under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

Environmental Statutes and Regulations

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Alabama Power in Item 7 of the Form 10-K for additional information regarding the final effluent guidelines rule and the final rule revising the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs.

On April 25, 2017, the EPA published a notice announcing it would reconsider the effluent guidelines rule, which had been finalized in November 2015. On June 6, 2017, the EPA proposed a rule establishing a stay of the compliance deadlines for certain effluent limitations and pretreatment standards under the rule.

On June 27, 2017, the EPA and the U.S. Army Corps of Engineers proposed to rescind the final rule that revised the regulatory definition of waters of the U.S. for all CWA programs. The final rule has been stayed since October 2015 by the U.S. Court of Appeals for the Sixth Circuit.

The ultimate outcome of these matters cannot be determined at this time.

Global Climate Issues

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" of Alabama Power in Item 7 of the Form 10-K for additional information.

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. The executive order specifically directs the EPA to review the Clean Power Plan and final greenhouse gas emission standards for new, modified, and reconstructed electric generating units and, if appropriate, take action to suspend, revise, or rescind those rules.

On June 1, 2017, the U.S. President announced that the United States will withdraw from the non-binding Paris Agreement and begin renegotiation of its terms.

The ultimate outcome of these matters cannot be determined at this time.

FERC Matters

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters" of Alabama Power in Item 7 of the Form 10-K for additional information regarding the traditional electric operating companies' and Southern Power's market power proceeding and amendment to their market-rate tariff.

On May 17, 2017, the FERC accepted the traditional electric operating companies' (including Alabama Power's) and Southern Power's compliance filing accepting the terms of the FERC's February 2, 2017 order regarding an amendment by the traditional electric operating companies (including Alabama Power) and Southern Power to their market-based rate tariff. While the FERC's order references the traditional electric operating companies' (including Alabama Power's) and Southern Power's market power proceeding, it remains a separate, ongoing matter.

Retail Regulatory Matters

Alabama Power's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Alabama PSC. Alabama Power currently recovers its costs from the regulated retail business primarily through Rate RSE, Rate CNP, Rate ECR, and Rate NDR. In addition, the Alabama PSC issues accounting orders to address current events impacting Alabama Power. See Notes 1 and 3 to the financial statements of Alabama Power under "Nuclear Outage Accounting Order" and "Retail Regulatory Matters," respectively, in Item 8 of the Form 10-K for additional information regarding Alabama Power's rate mechanisms and accounting orders. The recovery balance of each regulatory clause for Alabama Power is reported in Note (B) to the Condensed Financial Statements herein.

Other Matters

Alabama Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Alabama Power is subject to certain claims and legal actions arising in the ordinary course of business. Alabama Power's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions , CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation against Alabama Power cannot be predicted at this time; however, for current proceedings not specifically reported in Note (B) to the Condensed Financial Statements herein , management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Alabama Power's financial statements. See Note (B) to the Condensed Financial

Statements herein 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

Alabama Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Alabama Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Alabama Power'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. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Alabama Power in Item 7 of the Form 10-K for a complete discussion of Alabama Power's critical accounting policies and estimates related to Utility Regulation, Asset Retirement Obligations, Pension and Other Postretirement Benefits, and Contingent Obligations.

Recently Issued Accounting Standards

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 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.

While Alabama Power expect s most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of all revenue arrangements. The majority of Alabama Power'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 . Alabama Power expect s that the revenue from contracts with these customers will not result in a significant shift in the timing of revenue recognition for such sales .

Alabama Power's ongoing evaluation of other revenue streams and related contracts includes unregulated sales to customers. Some revenue arrangements, such as alternative revenue programs, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed or presented separately from revenues under ASC 606 on Alabama Power's financial statements, if material. In addition, the power and utilities industry continues to evaluate other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). Although final implementation guidance has not been issued, Alabama Power expect s CIAC to be out of the scope of ASC 606.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. Alabama Power intend s to use the modified retrospective method of adoption effective January 1, 2018. Alabama Power has also elected to utilize practical expedients which allow 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, disclosures will include comparative information on 2018 financial statement line items under current guidance. While the adoption of ASC 606, including the cumulative-effect adjustment, is not expected to have a material impact on either the timing or amount of revenues recognized in Alabama Power's financial statements, Alabama Power will continue to evaluate the requirements, as well as any additional clarifying guidance that may be issued.

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 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 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 annual periods beginning after December 15, 2017, including interim periods within those annual periods. Alabama Power is currently evaluating the new standard. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in Alabama Power'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 adoption of ASU 2017-07 is not expected to have a material impact on Alabama Power's financial statements.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Overview" of Alabama Power in Item 7 of the Form 10-K for additional information. Alabama Power's financial condition remained stable at June 30, 2017 . Alabama Power 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 " Capital Requirements and Contractual Obligations ," " Sources of Capital ," and " Financing Activities " herein for additional information.

Net cash provided from operating activities totaled $672 million for the first six months of 2017 , a decrease of $135 million as compared to the first six months of 2016 . The decrease in net cash provided from operating activities was primarily due to the receipt of income tax refunds in 2016 as a result of bonus depreciation. Net cash used for investing activities totaled $759 million for the first six months of 2017 primarily due to gross property additions related to distribution, environmental, transmission, and steam generation. Net cash provided from financing activities totaled $306 million for the first six months of 2017 primarily due to an issuance of long-term debt and additional capital contributions from Southern Company, partially offset by common stock dividend payments and a redemption of long-term debt. Fluctuations in cash flows from financing activities vary from period to period based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for the first six months of 2017 include increases of $547 million in long-term debt, primarily due to the issuance of additional senior notes, $367 million in property, plant, and equipment, primarily due to additions to distribution, steam generation, and transmission, $337 million in additional paid-in capital due to capital contributions from Southern Company, and $219 million in cash and cash equivalents, as well as a decrease of $200 million in securities due within one year.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Alabama Power in Item 7 of the Form 10-K for a description of Alabama Power's capital requirements for its construction program, including estimated capital expenditures to comply with existing environmental statutes and regulations, scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, purchase commitments, and trust funding requirements. Approximately $361 million will be required through June 30, 2018 to fund maturities of long-term debt.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – General" and " – Global Climate Issues" of Alabama Power in Item 7 of the Form 10-K for additional information on Alabama Power's environmental compliance strategy.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing 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.

Sources of Capital

Alabama Power 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, short-term debt, term loans, external security issuances, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Alabama Power in Item 7 of the Form 10-K for additional information.

Alabama Power'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 June 30, 2017 , Alabama Power had approximately $639 million of cash and cash equivalents. Committed credit arrangements with banks at June 30, 2017 were as follows:

Expires					Expires Within One Year	
2017	**2018**	**2022**	**Total**	**Unused**	**Term Out**	**No Term Out**
			(in millions)			
$ 3	$ 532	$ 800	$ 1,335	$ 1,335	$ —	$ 35

See Note 6 to the financial statements of Alabama Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under " Bank Credit Arrangements " herein for additional information.

As reflected in the table above, in May 2017, Alabama Power amended its $800 million multi-year credit arrangement, which, among other things, extended the maturity date from 2020 to 2022.

Most of these bank credit arrangements, as well as Alabama Power's term loan arrangements, contain covenants that limit debt levels and contain cross-acceleration provisions to other indebtedness (including guarantee obligations) of Alabama Power. Such cross-acceleration provisions to other indebtedness would trigger an event of default if Alabama Power defaulted on indebtedness, the payment of which was then accelerated. At June 30, 2017 , Alabama Power 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, Alabama Power expects to renew or replace its bank credit arrangements as needed, prior to expiration. In connection therewith, Alabama Power 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 Alabama Power's pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support was approximately $890 million as of June 30, 2017 . At June 30, 2017 , Alabama Power had no fixed rate pollution control revenue bonds outstanding that were required to be reoffered within the next 12 months.

Alabama Power also has substantial cash flow from operating activities and access to capital markets, including a commercial paper program, to meet liquidity needs. Alabama Power may meet short-term cash needs through its commercial paper program. Alabama Power 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 Alabama Power and the other traditional electric operating companies. Proceeds from such issuances for the benefit of Alabama Power are loaned directly to Alabama Power. The obligations of each traditional electric operating company under these arrangements are several and there is no cross-affiliate credit support.

Details of commercial paper borrowings were as follows:

	Short-term Debt During the Period (*)		
	Average Amount Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*
Commercial paper	$ 28	1.1%	$ 200

(*) Average and maximum amounts are based upon daily balances during the three -month period ended June 30, 2017 . No short-term debt was outstanding at June 30, 2017 .

Alabama Power believes the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and operating cash flows.

Credit Rating Risk

At June 30, 2017 , Alabama Power 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 June 30, 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	$ 326

Included in these amounts are certain agreements that could require collateral in the event that either Alabama Power or Georgia Power has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of Alabama Power 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 Alabama Power) from stable to negative.

Financing Activities

In February 2017, Alabama Power repaid at maturity $200 million aggregate principal amount of Series 2007A 5.55% Senior Notes.

In March 2017, Alabama Power issued $550 million aggregate principal amount of Series 2017A 2.45% Senior Notes due March 30, 2022. The proceeds were used to repay Alabama Power's short-term indebtedness and for general corporate purposes, including Alabama Power's continuous construction program.

Subsequent to June 30, 2017, Alabama Power 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 addition to any financings that may be necessary to meet capital requirements and contractual obligations, Alabama Power 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.

GEORGIA POWER COMPANY

GEORGIA POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	**2017**	2016
	(in millions)		*(in millions)*	
Operating Revenues:				
Retail revenues	**$ 1,904**	$ 1,907	**$ 3,593**	$ 3,624
Wholesale revenues, non-affiliates	**40**	40	**79**	82
Wholesale revenues, affiliates	**9**	10	**17**	15
Other revenues	**95**	94	**191**	202
Total operating revenues	**2,048**	2,051	**3,880**	3,923
Operating Expenses:				
Fuel	**445**	439	**815**	815
Purchased power, non-affiliates	**103**	92	**191**	175
Purchased power, affiliates	**138**	111	**310**	250
Other operations and maintenance	**399**	439	**781**	896
Depreciation and amortization	**223**	214	**444**	425
Taxes other than income taxes	**101**	100	**199**	197
Total operating expenses	**1,409**	1,395	**2,740**	2,758
Operating Income	**639**	656	**1,140**	1,165
Other Income and (Expense):				
Interest expense, net of amounts capitalized	**(104)**	(99)	**(205)**	(193)
Other income (expense), net	**16**	8	**36**	26
Total other income and (expense)	**(88)**	(91)	**(169)**	(167)
Earnings Before Income Taxes	**551**	565	**971**	998
Income taxes	**199**	211	**355**	371
Net Income	**352**	354	**616**	627
Dividends on Preferred and Preference Stock	**5**	5	**9**	9
Net Income After Dividends on Preferred and Preference Stock	**$ 347**	$ 349	**$ 607**	$ 618

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	**2017**	2016
	(in millions)		*(in millions)*	
Net Income	**$ 352**	$ 354	**$ 616**	$ 627
Other comprehensive income (loss):				
Qualifying hedges:				
Reclassification adjustment for amounts included in net income, net of tax of $-, $-, $1, and $1, respectively	**1**	1	**2**	1
Total other comprehensive income (loss)	**1**	1	**2**	1
Comprehensive Income	**$ 353**	$ 355	**$ 618**	$ 628

The accompanying notes as they relate to Georgia Power are an integral part of these condensed financial statements.

GEORGIA POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Six Months Ended June 30,	
	2017	2016
	(in millions)	
Operating Activities:		
Net income	**$ 616**	$ 627
Adjustments to reconcile net income to net cash provided from operating activities --		
Depreciation and amortization, total	**543**	530
Deferred income taxes	**159**	157
Allowance for equity funds used during construction	**(25)**	(24)
Deferred expenses	**41**	39
Pension, postretirement, and other employee benefits	**(45)**	(28)
Settlement of asset retirement obligations	**(62)**	(52)
Other, net	**(39)**	36
Changes in certain current assets and liabilities —		
-Receivables	**(150)**	(25)
-Fossil fuel stock	**(32)**	61
-Other current assets	**(22)**	10
-Accounts payable	**(153)**	6
-Accrued taxes	**(194)**	(137)
-Accrued compensation	**(65)**	(44)
-Retail fuel cost over recovery	**(84)**	1
-Other current liabilities	**(6)**	16
Net cash provided from operating activities	**482**	1,173
Investing Activities:		
Property additions	**(1,284)**	(1,058)
Nuclear decommissioning trust fund purchases	**(271)**	(386)
Nuclear decommissioning trust fund sales	**266**	380
Cost of removal, net of salvage	**(32)**	(34)
Change in construction payables, net of joint owner portion	**1**	(75)
Payments pursuant to LTSAs	**(56)**	(14)
Sale of property	**63**	—
Other investing activities	**(12)**	17
Net cash used for investing activities	**(1,325)**	(1,170)
Financing Activities:		
Increase in notes payable, net	**37**	39
Proceeds —		
Capital contributions from parent company	**380**	239
Senior notes	**850**	650
FFB loan	**—**	300
Short-term borrowings	**800**	—
Redemptions and repurchases —		
Pollution control revenue bonds	**(27)**	(4)
Senior notes	**(450)**	(500)
Payment of common stock dividends	**(640)**	(653)
Other financing activities	**(19)**	(20)
Net cash provided from financing activities	**931**	51
Net Change in Cash and Cash Equivalents	**88**	54
Cash and Cash Equivalents at Beginning of Period	**3**	67
Cash and Cash Equivalents at End of Period	**$ 91**	$ 121
Supplemental Cash Flow Information:		
Cash paid during the period for —		
Interest (net of $11 and $10 capitalized for 2017 and 2016, respectively)	**$ 186**	$ 174

Income taxes, net	**213**	78
Noncash transactions — Accrued property additions at end of period	**348**	288

The accompanying notes as they relate to Georgia Power are an integral part of these condensed financial statements.

GEORGIA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Assets	**At June 30, 2017**	At December 31, 2016
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 91**	$ 3
Receivables —		
Customer accounts receivable	**565**	523
Unbilled revenues	**251**	224
Joint owner accounts receivable	**199**	57
Other accounts and notes receivable	**62**	81
Affiliated	**22**	18
Accumulated provision for uncollectible accounts	**(3)**	(3)
Fossil fuel stock	**330**	298
Materials and supplies	**477**	479
Prepaid expenses	**55**	105
Other regulatory assets, current	**193**	193
Other current assets	**22**	38
Total current assets	**2,264**	2,016
Property, Plant, and Equipment:		
In service	**34,410**	33,841
Less: Accumulated provision for depreciation	**11,502**	11,317
Plant in service, net of depreciation	**22,908**	22,524
Nuclear fuel, at amortized cost	**559**	569
Construction work in progress	**5,422**	4,939
Total property, plant, and equipment	**28,889**	28,032
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**56**	60
Nuclear decommissioning trusts, at fair value	**874**	814
Miscellaneous property and investments	**51**	46
Total other property and investments	**981**	920
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**675**	676
Other regulatory assets, deferred	**2,790**	2,774
Other deferred charges and assets	**589**	417
Total deferred charges and other assets	**4,054**	3,867
Total Assets	**$ 36,188**	$ 34,835

The accompanying notes as they relate to Georgia Power are an integral part of these condensed financial statements.

GEORGIA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	**At June 30, 2017**	At December 31, 2016
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 261**	$ 460
Notes payable	**1,228**	391
Accounts payable —		
Affiliated	**367**	438
Other	**657**	589
Customer deposits	**269**	265
Accrued taxes	**212**	407
Accrued interest	**115**	106
Accrued compensation	**141**	224
Asset retirement obligations, current	**251**	299
Other current liabilities	**185**	297
Total current liabilities	**3,686**	3,476
Long-term Debt	**10,793**	10,225
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**6,163**	6,000
Deferred credits related to income taxes	**118**	121
Accumulated deferred ITCs	**251**	256
Employee benefit obligations	**652**	703
Asset retirement obligations, deferred	**2,340**	2,233
Other deferred credits and liabilities	**206**	199
Total deferred credits and other liabilities	**9,730**	9,512
Total Liabilities	**24,209**	23,213
Preferred Stock	**45**	45
Preference Stock	**221**	221
Common Stockholder's Equity:		
Common stock, without par value —		
Authorized — 20,000,000 shares		
Outstanding — 9,261,500 shares	**398**	398
Paid-in capital	**7,274**	6,885
Retained earnings	**4,052**	4,086
Accumulated other comprehensive loss	**(11)**	(13)
Total common stockholder's equity	**11,713**	11,356
Total Liabilities and Stockholder's Equity	**$ 36,188**	$ 34,835

The accompanying notes as they relate to Georgia Power are an integral part of these condensed financial statements.

GEORGIA POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

SECOND QUARTER 2017 vs. SECOND QUARTER 2016
AND
YEAR-TO-DATE 2017 vs. YEAR-TO-DATE 2016

OVERVIEW

Georgia Power operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located within the State of Georgia and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of Georgia Power's business of providing electric service. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, stringent environmental standards, reliability, fuel, capital expenditures, and restoration following major storms. Georgia Power 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 Georgia Power for the foreseeable future.

On March 29, 2017, the EPC Contractor filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. To provide for a continuation of work at Plant Vogtle Units 3 and 4, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into an interim assessment agreement with the EPC Contractor (Interim Assessment Agreement), which the bankruptcy court approved on March 30, 2017. On June 9, 2017, Georgia Power and the other Vogtle Owners and Toshiba entered into a settlement agreement regarding the Toshiba Guarantee (Guarantee Settlement Agreement). Pursuant to the Guarantee Settlement Agreement, Toshiba acknowledged the amount of its obligation under the Toshiba Guarantee is $3.68 billion (Guarantee Obligations), of which Georgia Power's proportionate share is approximately $1.7 billion, and that the Guarantee Obligations exist regardless of whether Plant Vogtle Units 3 and 4 are completed. Additionally, on June 9, 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the EPC Contractor entered into a services agreement (Services Agreement), which was amended and restated on July 20, 2017, for the EPC Contractor to transition construction management of Plant Vogtle Units 3 and 4 to Southern Nuclear and to provide ongoing design, engineering, and procurement services to Southern Nuclear. On July 27, 2017, the Services Agreement, and the EPC Contractor's rejection of the Vogtle 3 and 4 Agreement, became effective upon approval by the DOE and the Interim Assessment Agreement expired pursuant to its terms. The Services Agreement will continue until the start-up and testing of Plant Vogtle Units 3 and 4 is complete and electricity is generated and sold from both units. The Services Agreement is terminable by the Vogtle Owners upon 30 days' written notice.

Georgia Power and the other Vogtle Owners are continuing to conduct comprehensive schedule and cost-to-complete assessments, as well as cancellation cost assessments, to determine the impact of the EPC Contractor's bankruptcy filing on the construction cost and schedule for Plant Vogtle Units 3 and 4. Georgia Power will continue working with the Georgia PSC and the other Vogtle Owners to determine future actions related to Plant Vogtle Units 3 and 4, including, but not limited to, the status of construction and rate recovery, and currently expects to include its recommendation in its seventeenth Vogtle Construction Monitoring (VCM) report to be filed with the Georgia PSC in late August 2017.

An inability or other failure by Toshiba to perform its obligations under the Guarantee Settlement Agreement could have a further material impact on the net cost to the Vogtle Owners to complete construction of Plant Vogtle Units 3 and 4 and, therefore, on Georgia Power's financial statements. The ultimate outcome of these matters also is dependent on the completion of the assessments described above, as well as the related regulatory treatment, and cannot be determined at this time. See FUTURE EARNINGS POTENTIAL – " Retail Regulatory Matters – Nuclear Construction " herein for additional information on Plant Vogtle Units 3 and 4, including Georgia Power's preliminary cost-to-complete and cancellation cost assessments for Plant Vogtle Units 3 and 4.

Georgia Power continues to focus on several key performance indicators including, but not limited to, customer satisfaction, plant availability, system reliability, the execution of major construction projects, and net income after dividends on preferred and preference stock.

RESULTS OF OPERATIONS

Net Income

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(2)	(0.6)	$(11)	(1.8)

Georgia Power's net income after dividends on preferred and preference stock for the second quarter 2017 was $347 million compared to $349 million for the corresponding period in 2016 . For year-to-date 2017 , net income after dividends on preferred and preference stock was $607 million compared to $618 million for the corresponding period in 2016 . The decreases were primarily due to milder weather as compared to the corresponding periods in 2016 , partially offset by lower non-fuel operations and maintenance expenses.

Retail Revenues

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(3)	(0.2)	$(31)	(0.9)

In the second quarter 2017 , retail revenues were $1.90 billion compared to $1.91 billion for the corresponding period in 2016 . For year-to-date 2017 , retail revenues were $3.59 billion compared to $3.62 billion for the corresponding period in 2016 .

Details of the changes in retail revenues were as follows:

	Second Quarter 2017		**Year-to-Date 2017**	
	(in millions)	*(% change)*	*(in millions)*	*(% change)*
Retail – prior year	$ 1,907		$ 3,624	
Estimated change resulting from –				
Rates and pricing	(7)	(0.4)	19	0.5
Sales growth (decline)	1	0.1	(11)	(0.3)
Weather	(38)	(2.0)	(110)	(3.1)
Fuel cost recovery	41	2.1	71	2.0
Retail – current year	$ 1,904	(0.2)%	$ 3,593	(0.9)%

Revenues associated with changes in rates and pricing decreased in the second quarter and increased year-to-date 2017 when compared to the corresponding periods in 2016. An increase in revenues related to the recovery of Plant Vogtle Units 3 and 4 construction financing costs under the NCCR tariff was more than offset in the second quarter 2017 by the rate pricing effect of decreased customer usage and lower contributions from commercial and industrial customers under a rate plan for variable demand-driven pricing. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Constructions" of Georgia Power in Item 7 of the Form 10-K and FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction – Regulatory Matters" herein for additional information related to the NCCR tariff.

Revenues attributable to changes in sales were essentially flat in the second quarter and decreased year-to-date 2017 when compared to the corresponding periods in 2016 . Weather-adjusted residential KWH sales increased 0.3%, weather-adjusted commercial KWH sales increased 0.4%, and weather-adjusted industrial KWH sales decreased

1.3% in the second quarter 2017 when compared to the corresponding period in 2016 . For year-to-date 2017 , weather-adjusted residential KWH sales increased 0.8%, weather-adjusted commercial KWH sales decreased 1.0%, and weather-adjusted industrial KWH sales decreased 2.2% when compared to the corresponding period in 2016 . An increase of approximately 29,000 residential customers since June 30, 2016 contributed to the increase in weather-adjusted residential KWH sales. A decline in average customer usage resulting from an increase in energy saving initiatives and electronic commerce transactions contributed to the decrease in weather-adjusted commercial KWH sales, partially offset by an increase of approximately 2,000 commercial customers since June 30, 2016 . Decreased demand in the chemicals, paper, and transportation sectors was the main contributor to the decrease in weather-adjusted industrial KWH sales, partially offset by increased demand in the non-manufacturing and rubber sectors. Despite a more stable dollar and improving global economy, the industrial sector remains constrained by economic policy uncertainty.

Fuel revenues and costs are allocated between retail and wholesale jurisdictions. Retail fuel cost recovery revenues increased $41 million and $71 million in the second quarter and year-to-date 2017 , respectively, when compared to the corresponding periods in 2016 primarily due to higher natural gas prices, partially offset by lower energy sales resulting from milder weather as compared to the corresponding periods in 2016 . Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses and do not affect net income. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" of Georgia Power in Item 7 of the Form 10-K for additional information.

Other Revenues

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$1	1.1	$(11)	(5.4)

For year-to-date 2017 , other revenues were $191 million compared to $202 million for the corresponding period in 2016 . The decrease was primarily due to a $14 million adjustment in 2016 for customer temporary facilities services revenues and an $8 million decrease in open access transmission tariff revenues, partially offset by a $7 million increase in outdoor lighting sales revenues primarily attributable to LED conversions and a $3 million increase in solar application fee revenue.

Fuel and Purchased Power Expenses

	Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
	(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
Fuel	$ 6	1.4	$ —	—
Purchased power – non-affiliates	11	12.0	16	9.1
Purchased power – affiliates	27	24.3	60	24.0
Total fuel and purchased power expenses	$ 44		$ 76	

In the second quarter 2017 , total fuel and purchased power expenses were $686 million compared to $642 million in the corresponding period in 2016 . The increase was primarily due to a $45 million increase in the average cost of fuel and purchased power primarily related to higher natural gas prices, slightly offset by a decrease related to the volume of KWHs generated and purchased due to milder weather, resulting in lower customer demand.

For year-to-date 2017 , total fuel and purchased power expenses were $1.32 billion compared to $1.24 billion in the corresponding period in 2016 . The increase was primarily due to an $89 million increase in the average cost of fuel and purchased power primarily related to higher natural gas prices, partially offset by a net decrease of $13 million

related to the volume of KWHs generated and purchased due to milder weather, resulting in lower customer demand.

Fuel and purchased power energy transactions do not have a significant impact on earnings since these fuel expenses are generally offset by fuel revenues through Georgia Power's fuel cost recovery mechanism. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" of Georgia Power in Item 7 of the Form 10-K for additional information.

Details of Georgia Power's generation and purchased power were as follows:

	Second Quarter 2017	Second Quarter 2016	**Year-to-Date 2017**	Year-to-Date 2016
Total generation *(in billions of KWHs)*	**16**	17	**30**	33
Total purchased power *(in billions of KWHs)*	**6**	6	**13**	12
Sources of generation *(percent)* —				
Coal	**36**	36	**32**	33
Nuclear	**25**	24	**25**	24
Gas	**37**	38	**41**	40
Hydro	**2**	2	**2**	3
Cost of fuel, generated *(in cents per net KWH)* —				
Coal	**3.20**	3.37	**3.23**	3.45
Nuclear	**0.84**	0.84	**0.84**	0.85
Gas	**2.75**	2.18	**2.76**	2.10
Average cost of fuel, generated *(in cents per net KWH)*	**2.43**	2.29	**2.41**	2.26
Average cost of purchased power *(in cents per net KWH)* (*)	**4.76**	4.45	**4.61**	4.38

(*) Average cost of purchased power includes fuel purchased by Georgia Power for tolling agreements where power is generated by the provider.

Fuel

In the second quarter 2017 , fuel expense was $445 million compared to $439 million in the corresponding period in 2016 . The increase was primarily due to a 26.2% increase in the average cost of natural gas per KWH generated, partially offset by a 6.1% decrease in the volume of KWHs generated by coal and natural gas. For year-to-date 2017 , fuel expense remained flat compared to the corresponding period in 2016 primarily resulting from a 31.4% increase in the average cost of natural gas per KWH generated, offset by a 9.5% decrease in the volume of KWHs generated by coal and natural gas.

Purchased Power – Non-Affiliates

In the second quarter 2017 , purchased power expense from non-affiliates was $103 million compared to $92 million in the corresponding period in 2016 . For year-to-date 2017 , purchased power expense from non-affiliates was $191 million compared to $175 million in the corresponding period in 2016 . The increases were primarily due to increases in the volume of KWHs purchased of 13.4% and 11.6% in the second quarter and year-to-date 2017 , respectively, due to unplanned outages at Georgia Power-owned generating units.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation.

Purchased Power – Affiliates

In the second quarter 2017 , purchased power expense from affiliates was $138 million compared to $111 million in the corresponding period in 2016 . The increase was primarily the result of an 11.1% increase in the average cost per KWH purchased primarily resulting from higher natural gas prices and a 5.9% increase in the volume of KWHs purchased due to unplanned outages at Georgia Power-owned generating units and to support Southern Company system transmission reliability.

For year-to-date 2017 , purchased power expense from affiliates was $310 million compared to $250 million in the corresponding period in 2016 . The increase was primarily the result of a 10.1% increase in the volume of KWHs purchased due to unplanned outages at Georgia Power-owned generating units and to support Southern Company system transmission reliability and an 8.8% increase in the average cost per KWH purchased primarily resulting from higher natural gas prices.

Energy purchases from affiliates will vary depending on demand and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, all as approved by the FERC.

Other Operations and Maintenance Expenses

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(40)	(9.1)	$(115)	(12.8)

In the second quarter 2017 , other operations and maintenance expenses were $399 million compared to $439 million in the corresponding period in 2016 . The decrease was primarily due to cost containment activities implemented in the third quarter 2016 that contributed to decreases of $14 million in generation maintenance costs and $9 million in transmission and distribution overhead line maintenance. Other factors include decreases of $9 million in customer accounts, service, and sales costs, $5 million in transmission station expenses, and $5 million in billing adjustments with integrated transmission system owners, partially offset by a $7 million increase in scheduled generation outage costs.

For year-to-date 2017 , other operations and maintenance expenses were $781 million compared to $896 million in the corresponding period in 2016 . The decrease was primarily due to cost containment activities implemented in the third quarter 2016 that contributed to decreases of $28 million in generation maintenance costs, $18 million in transmission and distribution maintenance costs, and $13 million in employee benefit costs. Other factors include a $19 million increase in gains from sales of integrated transmission system assets and a $14 million decrease in customer assistance expenses primarily in demand-side management costs related to the timing of new programs.

Depreciation and Amortization

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$9	4.2	$19	4.5

In the second quarter 2017 , depreciation and amortization was $223 million compared to $214 million in the corresponding period in 2016 . The increase was primarily due to a $7 million increase related to additional plant in service and a $4 million decrease in amortization of regulatory liabilities related to other cost of removal obligations that expired in December 2016.

For year-to-date 2017 , depreciation and amortization was $444 million compared to $425 million in the corresponding period in 2016 . The increase was primarily due to a $17 million increase related to additional plant in service and a $7 million decrease in amortization of regulatory liabilities related to other cost of removal obligations

that expired in December 2016, partially offset by a $5 million decrease in depreciation related to generating unit retirements in 2016.

Interest Expense, Net of Amounts Capitalized

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$5	5.1	$12	6.2

In the second quarter 2017 , interest expense, net of amounts capitalized was $104 million compared to $99 million in the corresponding period in 2016 . For year-to-date 2017 , interest expense, net of amounts capitalized was $205 million compared to $193 million in the corresponding period in 2016 . The increases were primarily due to senior notes issuances and additional long-term borrowings from the FFB.

See FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" herein for additional information on borrowings from the FFB.

Other Income (Expense), Net

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$8	100.0	$10	38.5

In the second quarter 2017 , other income (expense), net was $16 million compared to $8 million in the corresponding period in 2016 . For year-to-date 2017 , other income (expense), net was $36 million compared to $26 million in the corresponding period in 2016. The increases were primarily due to increases in gains on purchases of state tax credits.

Income Taxes

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(12)	(5.7)	$(16)	(4.3)

In the second quarter 2017 , income taxes were $199 million compared to $211 million in the corresponding period in 2016 . For year-to-date 2017 , income taxes were $355 million compared to $371 million in the corresponding period in 2016 . The decreases were primarily due to increased state ITCs and lower pre-tax earnings.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Georgia Power's future earnings potential. The level of Georgia Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Georgia Power's business of providing electric service. These factors include Georgia Power'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. Completing the cost assessments and determining future actions related to Plant Vogtle Units 3 and 4 construction and rate recovery are also major factors. Future earnings will be driven primarily by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies, increasing volumes of electronic commerce transactions, and higher multi-family home construction. Earnings are subject to a variety of other factors. These factors include weather, competition, new energy contracts with other utilities, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in Georgia Power's service territory. Demand for electricity is primarily

driven by economic growth. The pace of economic growth and electricity demand may be affected by changes in regional and global economic conditions, which may impact future earnings.

Current proposals related to potential federal tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals, including any potential changes to the availability of nuclear PTCs, is dependent on the final form of any legislation enacted and the related transition rules and cannot be determined at this time, but could have a material impact on Georgia Power's financial statements.

For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Georgia Power in Item 7 of the Form 10-K and RISK FACTORS in Item 1A herein.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Georgia Power's Environmental Compliance Cost Recovery (ECCR) tariff allows for the recovery of capital and operations and maintenance costs related to environmental controls mandated by state and federal regulations. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are completed. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Georgia Power in Item 7 and Note 3 to the financial statements of Georgia Power under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

Environmental Statutes and Regulations

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Georgia Power in Item 7 of the Form 10-K for additional information regarding the EPA's eight-hour ozone National Ambient Air Quality Standard (NAAQS).

On June 2, 2017, the EPA published a final rule redesignating a 15-county area within metropolitan Atlanta to attainment for the 2008 eight-hour ozone NAAQS.

On June 18, 2017, the EPA published a notice delaying attainment designations for the 2015 eight-hour ozone NAAQS by one year, setting a revised deadline of October 1, 2018. The ultimate outcome of this matter cannot be determined at this time.

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Georgia Power in Item 7 of the Form 10-K for additional information regarding the final effluent guidelines rule and the final rule revising the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs.

On April 25, 2017, the EPA published a notice announcing it would reconsider the effluent guidelines rule, which had been finalized in November 2015. On June 6, 2017, the EPA proposed a rule establishing a stay of the compliance deadlines for certain effluent limitations and pretreatment standards under the rule.

On June 27, 2017, the EPA and the U.S. Army Corps of Engineers proposed to rescind the final rule that revised the regulatory definition of waters of the U.S. for all CWA programs. The final rule has been stayed since October 2015 by the U.S. Court of Appeals for the Sixth Circuit.

The ultimate outcome of these matters cannot be determined at this time.

Global Climate Issues

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" of Georgia Power in Item 7 of the Form 10-K for additional information.

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. The executive order specifically directs the EPA to review the Clean Power Plan and final greenhouse gas emission standards for new, modified, and reconstructed electric generating units and, if appropriate, take action to suspend, revise, or rescind those rules.

On June 1, 2017, the U.S. President announced that the United States will withdraw from the non-binding Paris Agreement and begin renegotiation of its terms.

The ultimate outcome of these matters cannot be determined at this time.

FERC Matters

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters" of Georgia Power in Item 7 of the Form 10-K for additional information regarding the traditional electric operating companies' and Southern Power's market power proceeding and amendment to their market-rate tariff.

On May 17, 2017, the FERC accepted the traditional electric operating companies' (including Georgia Power's) and Southern Power's compliance filing accepting the terms of the FERC's February 2, 2017 order regarding an amendment by the traditional electric operating companies (including Georgia Power) and Southern Power to their market-based rate tariff. While the FERC's order references the traditional electric operating companies' (including Georgia Power's) and Southern Power's market power proceeding, it remains a separate, ongoing matter.

Retail Regulatory Matters

Georgia Power's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Georgia PSC. Georgia Power currently recovers its costs from the regulated retail business through the 2013 ARP, which includes traditional base tariff rates, Demand-Side Management tariffs, ECCR tariffs, and Municipal Franchise Fee tariffs. In addition, financing costs related to the construction of Plant Vogtle Units 3 and 4 are being collected through the NCCR tariff and fuel costs are collected through a separate fuel cost recovery tariff. See " Nuclear Construction " herein and Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Nuclear Construction" in Item 8 of the Form 10-K for additional information regarding the NCCR tariff. Also see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" of Georgia Power in Item 7 of the Form 10-K for additional information regarding fuel cost recovery.

Renewables

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Integrated Resource Plan" of Georgia Power in Item 7 of the Form 10-K for additional information regarding renewable energy projects.

On May 16, 2017, the Georgia PSC approved Georgia Power's request to build, own, and operate a 139-MW solar generation facility at a U.S. Air Force base that is expected to be placed in service by the end of 2019.

During the six months ended June 30, 2017, Georgia Power continued construction of a 31-MW solar generation facility at a U.S. Marine Corps base that is expected to be placed in service in the fourth quarter 2017.

The ultimate outcome of these matters cannot be determined at this time.

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Integrated Resource Plan

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Integrated Resource Plan" of Georgia Power in Item 7 of the Form 10-K for additional information regarding Georgia Power's triennial Integrated Resource Plan.

On March 7, 2017, the Georgia PSC approved Georgia Power's decision to suspend work at a future generation site in Stewart County, Georgia, due to changing economics, including load forecasts and lower fuel costs. The timing of recovery for costs incurred of approximately $50 million will be determined by the Georgia PSC in a future base rate case. The ultimate outcome of this matter cannot be determined at this time.

Nuclear Construction

See Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Nuclear Construction" in Item 8 of the Form 10-K for additional information regarding the construction of Plant Vogtle Units 3 and 4, VCM reports, the NCCR tariff, and the Contractor Settlement Agreement.

Vogtle 3 and 4 Agreement and EPC Contractor Bankruptcy

In 2008, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into the Vogtle 3 and 4 Agreement, pursuant to which the EPC Contractor agreed to design, engineer, procure, construct, and test Plant Vogtle Units 3 and 4. Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Georgia Power's proportionate share of Plant Vogtle Units 3 and 4 is 45.7% .

The Vogtle 3 and 4 Agreement also provided for liquidated damages upon the EPC Contractor's failure to fulfill the schedule and certain performance guarantees, each subject to an aggregate cap of 10% of the contract price, or approximately $920 million (approximately $420 million based on Georgia Power's ownership interest). Under the Toshiba Guarantee, Toshiba guaranteed certain payment obligations of the EPC Contractor, including any liability of the EPC Contractor for abandonment of work. In January 2016, Westinghouse delivered to the Vogtle Owners $920 million of letters of credit from financial institutions (Westinghouse Letters of Credit) to secure a portion of the EPC Contractor's potential obligations under the Vogtle 3 and 4 Agreement. The Westinghouse Letters of Credit are subject to annual renewals through June 30, 2020 and require 60 days' written notice to Georgia Power in the event the Westinghouse Letters of Credit will not be renewed.

Under the terms of the Vogtle 3 and 4 Agreement, the EPC Contractor did not have the right to terminate the Vogtle 3 and 4 Agreement for convenience. In the event of an abandonment of work by the EPC Contractor, the maximum liability of the EPC Contractor under the Vogtle 3 and 4 Agreement was 40% of the contract price (approximately $1.7 billion based on Georgia Power's ownership interest).

On March 29, 2017, the EPC Contractor filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. To provide for a continuation of work at Plant Vogtle Units 3 and 4, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into the Interim Assessment Agreement, which the bankruptcy court approved on March 30, 2017.

The Interim Assessment Agreement provided, among other items, that during the term of the Interim Assessment Agreement (i) Georgia Power was obligated to pay, on behalf of the Vogtle Owners, all costs accrued by the EPC Contractor for subcontractors and vendors for services performed or goods provided, with these amounts paid to the EPC Contractor, except that amounts accrued for Fluor Corporation (Fluor) were paid directly to Fluor; (ii) the EPC Contractor provided certain engineering, procurement, and management services for Plant Vogtle Units 3 and 4, to the same extent as contemplated by the Vogtle 3 and 4 Agreement, and Georgia Power, on behalf of the Vogtle Owners, made payments of $5.4 million per week for these services; (iii) Georgia Power had the right to make payments, on behalf of the Vogtle Owners, directly to subcontractors and vendors who had accounts past due with the EPC Contractor; (iv) the EPC Contractor used commercially reasonable efforts to provide information reasonably requested by Georgia Power as was necessary to continue construction and investigation of the

completion status of Plant Vogtle Units 3 and 4; (v) the EPC Contractor rejected or accepted the Vogtle 3 and 4 Agreement by the termination of the Interim Assessment Agreement; and (vi) Georgia Power did not exercise any remedies against Toshiba under the Toshiba Guarantee. Under the Interim Assessment Agreement, all parties expressly reserved all rights and remedies under the Vogtle 3 and 4 Agreement and all related security and collateral under applicable law.

The Interim Assessment Agreement, as amended, expired on July 27, 2017. Georgia Power's aggregate liability for the Vogtle Owners under the Interim Assessment Agreement totaled approximately $650 million , of which $552 million had been paid or accrued as of June 30, 2017 . Georgia Power's proportionate share of this aggregate liability totaled approximately $297 million .

Subsequent to the EPC Contractor bankruptcy filing, a number of subcontractors to the EPC Contractor, including Fluor Enterprises, Inc., a subsidiary of Fluor, alleged non-payment by the EPC Contractor for amounts owed for work performed on Plant Vogtle Units 3 and 4. Georgia Power, acting for itself and as agent for the Vogtle Owners, has taken, and continues to take, actions to remove liens filed by these subcontractors through the posting of surety bonds. Georgia Power estimates the aggregate liability, through July 31, 2017, of the Vogtle Owners for the removal of subcontractor liens and payment of other EPC Contractor pre-petition accounts payable to total approximately $400 million , of which $354 million had been paid or accrued as of June 30, 2017 . Georgia Power's proportionate share of this aggregate liability totaled approximately $183 million .

On June 9, 2017, Georgia Power and the other Vogtle Owners and Toshiba entered the Guarantee Settlement Agreement. Pursuant to the Guarantee Settlement Agreement, Toshiba acknowledged the amount of its obligation under the Toshiba Guarantee is $3.68 billion , of which Georgia Power's proportionate share is approximately $1.7 billion, and that the Guarantee Obligations exist regardless of whether Plant Vogtle Units 3 and 4 are completed. The Guarantee Settlement Agreement also provides for a schedule of payments for the Guarantee Obligations, beginning in October 2017 and continuing through January 2021. In the event Toshiba receives certain payments, including sale proceeds, from or related to Westinghouse (or its subsidiaries) or Toshiba Nuclear Energy Holdings (UK) Limited (or its subsidiaries), it will hold a portion of such payments in trust for the Vogtle Owners and promptly pay them as offsets against any remaining Guarantee Obligations. Under the Guarantee Settlement Agreement, the Vogtle Owners will forbear from exercising certain remedies, including drawing on the Westinghouse Letters of Credit, until June 30, 2020, unless certain events of nonpayment, insolvency, or other material breach of the Guarantee Settlement Agreement by Toshiba occur. If such an event occurs, the balance of the Guarantee Obligations will become immediately due and payable, and the Vogtle Owners may exercise any and all rights and remedies, including drawing on the Westinghouse Letters of Credit without restriction. In addition, the Guarantee Settlement Agreement does not restrict the Vogtle Owners from fully drawing on the Westinghouse Letters of Credit in the event they are not renewed or replaced prior to the expiration date.

On June 23, 2017, Toshiba released a revised outlook for fiscal year 2016, which reflected a negative shareholders' equity balance of approximately $5 billion as of March 31, 2017, and announced that its independent audit process was continuing. Toshiba has also announced the existence of material events and conditions that raise substantial doubt about Toshiba's ability to continue as a going concern. As a result, substantial risk regarding the Vogtle Owners' ability to fully collect the Guarantee Obligations continues to exist. An inability or other failure by Toshiba to perform its obligations under the Guarantee Settlement Agreement could have a further material impact on the net cost to the Vogtle Owners to complete construction of Plant Vogtle Units 3 and 4 and, therefore, on Georgia Power's financial statements.

Additionally, on June 9, 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the EPC Contractor entered into the Services Agreement, which was amended and restated on July 20, 2017, for the EPC Contractor to transition construction management of Plant Vogtle Units 3 and 4 to Southern Nuclear and to provide ongoing design, engineering, and procurement services to Southern Nuclear. On July 20, 2017, the bankruptcy court approved the EPC Contractor's motion seeking authorization to (i) enter into the Services Agreement, (ii) assume and assign to the Vogtle Owners certain project-related contracts, (iii) join the Vogtle Owners as counterparties to certain assumed project-related contracts, and (iv) reject the Vogtle 3 and 4 Agreement.

The Services Agreement, and the EPC Contractor's rejection of the Vogtle 3 and 4 Agreement, became effective upon approval by the DOE on July 27, 2017. The Services Agreement will continue until the start-up and testing of Plant Vogtle Units 3 and 4 is complete and electricity is generated and sold from both units. The Services Agreement is terminable by the Vogtle Owners upon 30 days' written notice.

The ultimate outcome of these matters cannot be determined at this time.

Regulatory Matters

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4 with a certified capital cost of $4.418 billion . In addition, in 2009 the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows Georgia Power to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff by including the related CWIP accounts in rate base during the construction period. As of June 30, 2017 , Georgia Power had recovered approximately $1.4 billion of financing costs.

On December 20, 2016, the Georgia PSC voted to approve a settlement agreement (Vogtle Cost Settlement Agreement) resolving the following prudence matters: (i) none of the $3.3 billion of costs incurred through December 31, 2015 and reflected in the fourteenth VCM report will be disallowed from rate base on the basis of imprudence; (ii) the Contractor Settlement Agreement is reasonable and prudent and none of the amounts paid or to be paid pursuant to the Contractor Settlement Agreement should be disallowed from rate base on the basis of imprudence; (iii) financing costs on verified and approved capital costs will be deemed prudent provided they are incurred prior to December 31, 2019 and December 31, 2020 for Plant Vogtle Units 3 and 4, respectively; and (iv) (a) the in-service capital cost forecast will be adjusted to $5.680 billion (Revised Forecast), which includes a contingency of $240 million above Georgia Power's then current forecast of $5.440 billion , (b) capital costs incurred up to the Revised Forecast will be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, and (c) Georgia Power would have the burden to show that any capital costs above the Revised Forecast are reasonable and prudent. Under the terms of the Vogtle Cost Settlement Agreement, the certified in-service capital cost for purposes of calculating the NCCR tariff will remain at $4.418 billion . Construction capital costs above $4.418 billion will accrue AFUDC through the date each unit is placed in service. The ROE used to calculate the NCCR tariff was reduced from 10.95% (the ROE rate setting point authorized by the Georgia PSC in the 2013 ARP) to 10.00% effective January 1, 2016. For purposes of the AFUDC calculation, the ROE on costs between $4.418 billion and $5.440 billion will also be 10.00% and the ROE on any amounts above $5.440 billion would be Georgia Power's average cost of long-term debt. If the Georgia PSC adjusts Georgia Power's ROE rate setting point in a rate case prior to Plant Vogtle Units 3 and 4 being placed into retail rate base, then the ROE for purposes of calculating both the NCCR tariff and AFUDC will likewise be 95 basis points lower than the revised ROE rate setting point. If Plant Vogtle Units 3 and 4 are not placed in service by December 31, 2020, then (i) the ROE for purposes of calculating the NCCR tariff will be reduced an additional 300 basis points, or $8 million per month, and may, at the Georgia PSC's discretion, be accrued to be used for the benefit of customers, until such time as the units are placed in service and (ii) the ROE used to calculate AFUDC will be Georgia Power's average cost of long-term debt.

Under the terms of the Vogtle Cost Settlement Agreement, the Georgia PSC will determine, for retail ratemaking purposes, the process of transitioning Plant Vogtle Units 3 and 4 from a construction project to an operating plant no later than Georgia Power's base rate case required to be filed by July 1, 2019.

The Georgia PSC has approved fifteen VCM reports covering the periods through June 30, 2016, including construction capital costs incurred, which through that date totaled $3.7 billion . Georgia Power filed its sixteenth VCM report, covering the period from July 1 through December 31, 2016, requesting approval of $222 million of construction capital costs incurred during that period, with the Georgia PSC on February 27, 2017.

The ultimate outcome of these matters cannot be determined at this time.

Revised Cost and Schedule

Georgia Power and the other Vogtle Owners are continuing to conduct comprehensive schedule and cost-to-complete assessments, as well as cancellation cost assessments, to determine the impact of the EPC Contractor's bankruptcy filing on the construction cost and schedule for Plant Vogtle Units 3 and 4. Georgia Power's preliminary assessment results indicate that its proportionate share of the remaining estimated cost to complete Plant Vogtle Units 3 and 4 ranges as follows:

Preliminary in-service dates					
Unit 3	February 2021		–	March 2022	
Unit 4	February 2022		–	March 2023	
			(in billions)		
Preliminary estimated cost to complete	$	3.9	–	$	4.6
CWIP as of June 30, 2017		4.5			4.5
Guarantee Obligations		(1.7)			(1.7)
Estimated capital costs	**$**	**6.7**	–	**$**	**7.4**
Vogtle Cost Settlement Agreement Revised Forecast		(5.7)			(5.7)
Estimated net additional capital costs	**$**	**1.0**	–	**$**	**1.7**

Georgia Power's estimates for cost to complete and schedule are based on preliminary analysis and remain subject to further refinement of labor productivity and consumable and commodity quantities and costs.

Georgia Power's estimated financing costs during the construction period total approximately $3.1 billion to $3.5 billion , of which approximately $1.4 billion had been incurred through June 30, 2017.

Georgia Power's preliminary cancellation cost estimate results indicate that its proportionate share of the estimated cancellation costs is approximately $400 million . As a result, as of June 30, 2017, total estimated costs subject to evaluation by Georgia Power and the Georgia PSC in the event of a cancellation decision are as follows:

		Preliminary Cancellation Cost Estimate
		(in billions)
CWIP as of June 30, 2017	$	4.5
Financing costs collected, net of tax		1.4
Cancellation costs (*)		0.4
Total	**$**	**6.3**

(*) The estimate for cancellation costs includes, but is not limited to, costs to terminate contracts for construction and other services, as well as costs to secure the Plant Vogtle Units 3 and 4 construction site.

The Guarantee Obligations continue to exist in the event of cancellation. In addition, under Georgia law, prudently incurred costs related to certificated projects cancelled by the Georgia PSC are allowed recovery, including carrying costs, in future retail rates. Georgia Power will continue working with the Georgia PSC and the other Vogtle Owners to determine future actions related to Plant Vogtle Units 3 and 4, including, but not limited to, the status of construction and rate recovery, and currently expects to include its recommendation in its seventeenth VCM report to be filed with the Georgia PSC in late August 2017.

The ultimate outcome of these matters is dependent on the completion of the assessments described above, as well as the related regulatory treatment, and cannot be determined at this time.

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Other Matters

As of June 30, 2017 , Georgia Power had borrowed $2.6 billion related to Plant Vogtle Units 3 and 4 costs through a loan guarantee agreement between Georgia Power and the DOE and a multi-advance credit facility among Georgia Power, the DOE, and the FFB. See Note 6 to the financial statements of Georgia Power under "DOE Loan Guarantee Borrowings" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under " DOE Loan Guarantee Borrowings " herein for additional information, including applicable covenants, events of default, mandatory prepayment events, and conditions to borrowing.

The IRS has allocated PTCs to Plant Vogtle Units 3 and 4 which require that the applicable unit be placed in service prior to 2021. The net present value of Georgia Power's PTCs is estimated at approximately $400 million per unit.

There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4 at the federal and state level and additional challenges may arise if construction proceeds. Processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance matters, including the timely resolution of Inspections, Tests, Analyses, and Acceptance Criteria and the related approvals by the NRC, may arise if construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs.

If construction continues, the risk remains that challenges with labor productivity, fabrication, delivery, assembly, and installation of plant systems, structures, and components, or other issues could arise and may further impact project schedule and cost.

The ultimate outcome of these matters cannot be determined at this time.

See RISK FACTORS of Georgia Power in Item 1A of the Form 10-K for a discussion of certain risks associated with the licensing, construction, and operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. See additional risks in Item 1A herein regarding the EPC Contractor's bankruptcy.

Other Matters

Georgia Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Georgia Power is subject to certain claims and legal actions arising in the ordinary course of business. Georgia Power's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions , CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation against Georgia Power cannot be predicted at this time; however, for current proceedings not specifically reported in Note (B) to the Condensed Financial Statements herein , management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Georgia Power's financial statements. See Note (B) to the Condensed Financial Statements herein 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

Georgia Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Georgia Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Georgia Power'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. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Georgia Power in Item 7 of the Form 10-K for a complete discussion of Georgia Power's critical accounting policies and estimates related to Utility Regulation, Asset Retirement Obligations, Pension and Other Postretirement Benefits, and Contingent Obligations.

Recently Issued Accounting Standards

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 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.

While Georgia Power expect s most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of all revenue arrangements. The majority of Georgia Power'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 . Georgia Power expect s that the revenue from contracts with these customers will not result in a significant shift in the timing of revenue recognition for such sales .

Georgia Power's ongoing evaluation of other revenue streams and related contracts includes unregulated sales to customers. Some revenue arrangements are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed or presented separately from revenues under ASC 606 on Georgia Power's financial statements, if material. In addition, the power and utilities industry continues to evaluate other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). Although final implementation guidance has not been issued, Georgia Power expect s CIAC to be out of the scope of ASC 606.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. Georgia Power intend s to use the modified retrospective method of adoption effective January 1, 2018. Georgia Power has also elected to utilize practical expedients which allow 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, disclosures will include comparative information on 2018 financial statement line items under current guidance. While the adoption of ASC 606, including the cumulative-effect adjustment, is not expected to have a material impact on either the timing or amount of revenues recognized in Georgia Power's financial statements, Georgia Power will continue to evaluate the requirements, as well as any additional clarifying guidance that may be issued.

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 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 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 annual periods beginning after December 15, 2017, including interim periods within those annual periods. Georgia Power is currently evaluating the new standard. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in Georgia Power'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 adoption of ASU 2017-07 is not expected to have a material impact on Georgia Power's financial statements.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Overview" of Georgia Power in Item 7 of the Form 10-K for additional information. Georgia Power's financial condition remained stable at June 30, 2017 . Georgia Power intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit agreements to meet future capital and liquidity needs. See " Capital Requirements and Contractual Obligations ," " Sources of Capital ," and " Financing Activities " herein for additional information.

Net cash provided from operating activities totaled $482 million for the first six months of 2017 compared to $1.17 billion for the corresponding period in 2016 . The decrease was primarily due to the timing of vendor payments and an increase in under-recovered fuel costs. Net cash used for investing activities totaled $1.33 billion for the first six months of 2017 compared to $1.17 billion for the corresponding period in 2016 primarily related to installation of equipment to comply with environmental standards and construction of generation, transmission, and distribution facilities. Net cash provided from financing activities totaled $931 million for the first six months of 2017 compared to $51 million in the corresponding period in 2016 . The increase in cash provided from financing activities is primarily due to an increase in short-term borrowings, higher issuances of senior notes, and higher capital contributions received from Southern Company, partially offset by a decrease in borrowings from the FFB for construction of Plant Vogtle Units 3 and 4. Cash flows from financing activities vary from period to period based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for the first six months of 2017 include an increase in property, plant, and equipment of $857 million to comply with environmental standards and the construction of generation, transmission, and distribution facilities, an increase in notes payable of $837 million primarily due to issuances of short-term bank debt, an increase in paid-in capital of $389 million primarily due to capital contributions received from Southern Company, and an increase in long-term debt of $369 million primarily due to issuances of senior notes.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Georgia Power in Item 7 of the Form 10-K for a description of Georgia Power's capital requirements for its construction program, including estimated capital expenditures for Plant Vogtle Units 3 and 4 and to comply with existing environmental statutes and regulations, scheduled maturities of long-term debt, as well as related interest, derivative obligations, preferred and preference stock dividends, leases, purchase commitments, and trust funding requirements. Approximately $261 million will be required through June 30, 2018 to fund maturities of long-term debt. See " Sources of Capital " herein for additional information. Also see FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the

environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing generating units, to meet regulatory requirements; changes in FERC rules and regulations; Georgia PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Nuclear Construction" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under " Regulatory Matters – Georgia Power – Nuclear Construction " herein for information regarding additional factors that may impact construction expenditures, including Georgia Power's preliminary cost-to-complete and cancellation cost assessments for Plant Vogtle Units 3 and 4.

Sources of Capital

Georgia Power plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, external security issuances, term loans, equity contributions from Southern Company, and, to the extent available, borrowings from the FFB. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Georgia Power in Item 7 of the Form 10-K for additional information.

Georgia Power has entered into a loan guarantee agreement (Loan Guarantee Agreement) with the DOE, under which the proceeds of borrowings may be used to reimburse Georgia Power for Eligible Project Costs incurred in connection with its construction of Plant Vogtle Units 3 and 4. Under the Loan Guarantee Agreement, the DOE agreed to guarantee borrowings of up to $3.46 billion (not to exceed 70% of Eligible Project Costs) to be made by Georgia Power under a multi-advance credit facility (FFB Credit Facility) among Georgia Power, the DOE, and the FFB. Eligible Project Costs incurred through June 30, 2017 would allow for borrowings of up to $3.1 billion under the FFB Credit Facility, of which Georgia Power has borrowed $2.6 billion ; however, on July 27, 2017, Georgia Power entered into an amendment to the Loan Guarantee Agreement (LGA Amendment) to clarify the operation of the Loan Guarantee Agreement pending Georgia Power's completion of its comprehensive schedule, cost-to-complete, and cancellation cost assessments (Cost Assessments) for Plant Vogtle Units 3 and 4. Under the terms of the LGA Amendment, Georgia Power will not request any advances under the Loan Guarantee Agreement unless and until such time as Georgia Power has completed the Cost Assessments and made a determination to continue construction of Plant Vogtle Units 3 and 4 and satisfied certain other conditions related to continuing construction. See Note 6 to the financial statements of Georgia Power under "DOE Loan Guarantee Borrowings" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under " DOE Loan Guarantee Borrowings " herein for additional information regarding the Loan Guarantee Agreement, including applicable covenants, events of default, mandatory prepayment events, and additional conditions to borrowing. Also see Note (B) to the Condensed Financial Statements under " Regulatory Matters – Georgia Power – Nuclear Construction " herein for additional information regarding Plant Vogtle Units 3 and 4.

At June 30, 2017 , Georgia Power's current liabilities exceeded current assets by $1.42 billion . Georgia Power's current liabilities frequently exceed current assets because of scheduled maturities of long-term debt ($261 million at June 30, 2017) and the periodic use of short-term debt as a funding source ($1.2 billion at June 30, 2017), as well as significant seasonal fluctuations in cash needs. Georgia Power intends to utilize operating cash flows, short-term debt, external security issuances, term loans, equity contributions from Southern Company, and, to the extent available, borrowings from the FFB to fund its short-term capital needs. Georgia Power has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet liquidity needs.

At June 30, 2017 , Georgia Power had approximately $91 million of cash and cash equivalents. Georgia Power's committed credit arrangement with banks at June 30, 2017 was $1.75 billion of which $1.73 billion was unused. In May 2017, Georgia Power amended its multi-year credit arrangement, which, among other things, extended the maturity date from 2020 to 2022.

This bank credit arrangement, as well as Georgia Power's term loan arrangements, contains a covenant that limits debt levels and contains a cross-acceleration provision to other indebtedness (including guarantee obligations) of Georgia Power. Such cross-acceleration provision to other indebtedness would trigger an event of default if Georgia Power defaulted on indebtedness, the payment of which was then accelerated. At June 30, 2017 , Georgia Power was in compliance with this covenant. This bank credit arrangement does not contain a material adverse change clause at the time of borrowing.

Subject to applicable market conditions, Georgia Power expects to renew or replace this credit arrangement, as needed, prior to expiration. In connection therewith, Georgia Power may extend the maturity date and/or increase or decrease the lending commitments thereunder.

See Note 6 to the financial statements of Georgia Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under " Bank Credit Arrangements " herein for additional information.

A portion of the unused credit with banks is allocated to provide liquidity support to Georgia Power's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of June 30, 2017 was approximately $550 million . In June 2017, Georgia Power remarketed $318 million of variable rate pollution control bonds in index rate modes, reducing the liquidity support utilized under Georgia Power's bank credit arrangement. In addition, at June 30, 2017 , Georgia Power had $436 million of pollution control revenue bonds outstanding that were required to be reoffered within the next 12 months.

Georgia Power 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 Georgia Power and the other traditional electric operating companies. Proceeds from such issuances for the benefit of Georgia Power are loaned directly to Georgia Power. The obligations of each traditional electric operating company under these arrangements are several and there is no cross-affiliate credit support. Commercial paper is included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Short-term Debt at June 30, 2017		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)*
Commercial paper	$ 428	1.5%	$ 280	1.4%	$ 760
Short-term bank debt	800	2.0%	227	2.0%	800
Total	$ 1,228	1.8%	$ 507	1.6%	

(*) Average and maximum amounts are based upon daily balances during the three -month period ended June 30, 2017 .

Georgia Power believes the need for working capital can be adequately met by utilizing the commercial paper program, lines of credit, short-term bank notes, and operating cash flows.

Credit Rating Risk

At June 30, 2017 , Georgia Power did not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, and transmission, and, at June 30, 2017 , included contracts related to the construction of new generation at Plant Vogtle Units 3 and 4.

The maximum potential collateral requirements under these contracts at June 30, 2017 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements	
	(in millions)	
At BBB- and/or Baa3	$	87
Below BBB- and/or Baa3	$	1,210

Included in these amounts are certain agreements that could require collateral in the event that Georgia Power or Alabama Power has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of Georgia Power to access capital markets and would be likely to impact the cost at which it does so.

On March 20, 2017, Moody's revised its rating outlook for Georgia Power from stable to negative.

On March 24, 2017, S&P revised its consolidated credit rating outlook for Southern Company and its subsidiaries (including Georgia Power) from stable to negative.

On March 30, 2017, Fitch placed the ratings of Georgia Power on rating watch negative.

Financing Activities

In March 2017, Georgia Power issued $450 million aggregate principal amount of Series 2017A 2.00% Senior Notes due March 30, 2020 and $400 million aggregate principal amount of Series 2017B 3.25% Senior Notes due March 30, 2027. The proceeds were used to repay a portion of Georgia Power's short-term indebtedness and for general corporate purposes, including Georgia Power's continuous construction program.

In April 2017, Georgia Power purchased and held $27 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Fifth Series 1995. Georgia Power may reoffer these bonds to the public at a later date.

In June 2017, Georgia Power repaid at maturity $450 million aggregate principal amount of Series 2007B 5.70% Senior Notes.

In June 2017, Georgia Power entered into three floating rate bank loans in aggregate principal amounts of $50 million, $150 million, and $100 million, which mature on December 1, 2017, May 31, 2018, and June 28, 2018, respectively, and bear interest based on one-month LIBOR. Also in June 2017, Georgia Power borrowed $500 million pursuant to an uncommitted bank credit arrangement, which bears interest at a rate agreed upon by Georgia Power and the bank from time to time and is payable on no less than 30 days' demand by the bank. The proceeds from these bank loans were used to repay a portion of Georgia Power's existing indebtedness and for working capital and other general corporate purposes, including Georgia Power's continuous construction program.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Georgia Power 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.

GULF POWER COMPANY

GULF POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	**2017**	2016
	(in millions)		*(in millions)*	
Operating Revenues:				
Retail revenues	**$ 318**	$ 319	**$ 596**	$ 602
Wholesale revenues, non-affiliates	**12**	15	**30**	31
Wholesale revenues, affiliates	**10**	15	**47**	36
Other revenues	**17**	16	**34**	31
Total operating revenues	**357**	365	**707**	700
Operating Expenses:				
Fuel	**88**	107	**196**	201
Purchased power, non-affiliates	**35**	32	**67**	62
Purchased power, affiliates	**9**	4	**11**	5
Other operations and maintenance	**87**	77	**171**	155
Depreciation and amortization	**35**	42	**53**	80
Taxes other than income taxes	**28**	29	**55**	58
Loss on Plant Scherer Unit 3	**—**	—	**33**	—
Total operating expenses	**282**	291	**586**	561
Operating Income	**75**	74	**121**	139
Other Income and (Expense):				
Interest expense, net of amounts capitalized	**(13)**	(12)	**(24)**	(25)
Other income (expense), net	**(1)**	(1)	**(2)**	(2)
Total other income and (expense)	**(14)**	(13)	**(26)**	(27)
Earnings Before Income Taxes	**61**	61	**95**	112
Income taxes	**24**	24	**38**	44
Net Income	**37**	37	**57**	68
Dividends on Preference Stock	**2**	3	**4**	5
Net Income After Dividends on Preference Stock	**$ 35**	$ 34	**$ 53**	$ 63

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	**2017**	2016
	(in millions)		*(in millions)*	
Net Income	**$ 37**	$ 37	**$ 57**	$ 68
Other comprehensive income (loss):				
Qualifying hedges:				
Changes in fair value, net of tax of $-, $(1), $(1), and $(3), respectively	**(1)**	(1)	**(1)**	(4)
Total other comprehensive income (loss)	**(1)**	(1)	**(1)**	(4)
Comprehensive Income	**$ 36**	$ 36	**$ 56**	$ 64

The accompanying notes as they relate to Gulf Power are an integral part of these condensed financial statements.

GULF POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Six Months Ended June 30,	
	2017	2016
	(in millions)	
Operating Activities:		
Net income	**$ 57**	$ 68
Adjustments to reconcile net income to net cash provided from operating activities —		
Depreciation and amortization, total	**56**	83
Deferred income taxes	**19**	16
Loss on Plant Scherer Unit 3	**33**	—
Other, net	**(4)**	(3)
Changes in certain current assets and liabilities —		
-Receivables	**(25)**	(6)
-Fossil fuel stock	**4**	34
-Other current assets	**10**	1
-Accrued taxes	**7**	17
-Accrued compensation	**(17)**	(12)
-Over recovered regulatory clause revenues	**(19)**	5
-Other current liabilities	**3**	(7)
Net cash provided from operating activities	**124**	196
Investing Activities:		
Property additions	**(97)**	(68)
Cost of removal, net of salvage	**(9)**	(4)
Change in construction payables	**(14)**	(7)
Other investing activities	**(3)**	(5)
Net cash used for investing activities	**(123)**	(84)
Financing Activities:		
Increase (decrease) in notes payable, net	**(190)**	46
Proceeds —		
Common stock issued to parent	**175**	—
Capital contributions from parent company	**5**	5
Senior notes	**300**	—
Redemptions —		
Preference stock	**(150)**	—
Senior notes	**(85)**	(125)
Payment of common stock dividends	**(63)**	(60)
Other financing activities	**(4)**	(6)
Net cash used for financing activities	**(12)**	(140)
Net Change in Cash and Cash Equivalents	**(11)**	(28)
Cash and Cash Equivalents at Beginning of Period	**56**	74
Cash and Cash Equivalents at End of Period	**$ 45**	$ 46
Supplemental Cash Flow Information:		
Cash paid (received) during the period for —		
Interest (net of $- and $- capitalized for 2017 and 2016, respectively)	**$ 22**	$ 28
Income taxes, net	**7**	(3)
Noncash transactions — Accrued property additions at end of period	**19**	13

The accompanying notes as they relate to Gulf Power are an integral part of these condensed financial statements.

GULF POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Assets	At June 30, 2017	At December 31, 2016
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 45**	$ 56
Receivables —		
Customer accounts receivable	**77**	72
Unbilled revenues	**70**	55
Under recovered regulatory clause revenues	**26**	17
Other accounts and notes receivable	**11**	6
Affiliated	**8**	17
Accumulated provision for uncollectible accounts	**(1)**	(1)
Fossil fuel stock	**67**	71
Materials and supplies	**57**	55
Other regulatory assets, current	**55**	44
Other current assets	**17**	30
Total current assets	**432**	422
Property, Plant, and Equipment:		
In service	**5,156**	5,140
Less: Accumulated provision for depreciation	**1,427**	1,382
Plant in service, net of depreciation	**3,729**	3,758
Construction work in progress	**59**	51
Total property, plant, and equipment	**3,788**	3,809
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**57**	58
Other regulatory assets, deferred	**510**	512
Other deferred charges and assets	**22**	21
Total deferred charges and other assets	**589**	591
Total Assets	**$ 4,809**	$ 4,822

The accompanying notes as they relate to Gulf Power are an integral part of these condensed financial statements.

GULF POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	**At June 30, 2017**	At December 31, 2016
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 27**	$ 87
Notes payable	**78**	268
Accounts payable —		
Affiliated	**52**	59
Other	**46**	54
Customer deposits	**35**	35
Accrued taxes	**27**	20
Accrued interest	**9**	8
Accrued compensation	**23**	40
Deferred capacity expense, current	**22**	22
Other regulatory liabilities, current	**—**	16
Other current liabilities	**43**	40
Total current liabilities	**362**	649
Long-term Debt	**1,265**	987
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**966**	948
Employee benefit obligations	**92**	96
Deferred capacity expense	**108**	119
Asset retirement obligations, deferred	**125**	120
Other cost of removal obligations	**218**	249
Other regulatory liabilities, deferred	**46**	47
Other deferred credits and liabilities	**74**	71
Total deferred credits and other liabilities	**1,629**	1,650
Total Liabilities	**3,256**	3,286
Preference Stock	**—**	147
Common Stockholder's Equity:		
Common stock, without par value —		
Authorized — 20,000,000 shares		
Outstanding — June 30, 2017: 7,392,717 shares		
— December 31, 2016: 5,642,717 shares	**678**	503
Paid-in capital	**596**	589
Retained earnings	**280**	296
Accumulated other comprehensive income (loss)	**(1)**	1
Total common stockholder's equity	**1,553**	1,389
Total Liabilities and Stockholder's Equity	**$ 4,809**	$ 4,822

The accompanying notes as they relate to Gulf Power are an integral part of these condensed financial statements.

GULF POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

SECOND QUARTER 2017 vs. SECOND QUARTER 2016
AND
YEAR-TO-DATE 2017 vs. YEAR-TO-DATE 2016

OVERVIEW

Gulf Power operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located in northwest Florida and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of Gulf Power's business of providing electric service. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, stringent environmental standards, reliability, restoration following major storms, fuel, and capital expenditures. Gulf Power 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 Gulf Power for the foreseeable future.

On April 4, 2017, the Florida PSC approved a settlement agreement (2017 Rate Case Settlement Agreement) among Gulf Power and three intervenors with respect to Gulf Power's request to increase retail base rates. Under the terms of the 2017 Rate Case Settlement Agreement, Gulf Power increased rates effective with the first billing cycle in July 2017 to provide an annual overall net customer impact of approximately $54.3 million. The net customer impact consists of a $62.0 million increase in annual base revenues less an annual equivalent credit of approximately $7.7 million for 2017 for certain wholesale revenues to be provided through December 2019 through the purchased power capacity cost recovery clause. In addition, Gulf Power continued its authorized retail ROE midpoint (10.25%) and range (9.25% to 11.25%), is deemed to have an equity ratio of 52.5% for all retail regulatory purposes, and implemented new dismantlement accruals effective July 1, 2017. Gulf Power will also begin amortizing the regulatory asset associated with the investment balances remaining after the retirement of Plant Smith Units 1 and 2 (357 MWs) over 15 years effective January 1, 2018 and will implement new depreciation rates effective January 1, 2018. The 2017 Rate Case Settlement Agreement also resulted in a $32.5 million write-down of Gulf Power's ownership of Plant Scherer Unit 3 (205 MWs), which was recorded in the first quarter 2017. The remaining issues related to the inclusion of Gulf Power's investment in Plant Scherer Unit 3 in retail rates have been resolved as a result of the 2017 Rate Case Settlement Agreement, including recoverability of certain costs associated with the ongoing ownership and operation of the unit through the environmental cost recovery clause rate approved by the Florida PSC in November 2016.

Gulf Power 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 preference stock.

RESULTS OF OPERATIONS

Net Income

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$1	2.9	$(10)	(15.9)

Gulf Power's net income after dividends on preference stock for the second quarter 2017 was $35 million compared to $34 million for the corresponding period in 2016 . Gulf Power's net income after dividends on preference stock for year-to-date 2017 was $53 million compared to $63 million for the corresponding period in 2016 . The decrease for year-to-date 2017 was primarily due to a write-down of $32.5 million ($20 million after tax) of Gulf Power's ownership of Plant Scherer Unit 3 resulting from the 2017 Rate Case Settlement Agreement and higher operations and maintenance expenses, partially offset by lower depreciation and higher wholesale revenue. See Note (B) to the

Condensed Financial Statements under " Regulatory Matters – Gulf Power – Retail Base Rate Cases " herein for additional information regarding the 2017 Rate Case Settlement Agreement.

Retail Revenues

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(1)	(0.3)	$(6)	(1.0)

In the second quarter 2017 , retail revenues were $318 million compared to $319 million for the corresponding period in 2016 . For year-to-date 2017 , retail revenues were $596 million compared to $602 million for the corresponding period in 2016 .

Details of the changes in retail revenues were as follows:

	Second Quarter 2017		Year-to-Date 2017	
	(in millions)	*(% change)*	*(in millions)*	*(% change)*
Retail – prior year	$ 319		$ 602	
Estimated change resulting from –				
Rates and pricing	5	1.6	7	1.2
Sales decline	(1)	(0.3)	(3)	(0.5)
Weather	—	—	(6)	(1.0)
Fuel and other cost recovery	(5)	(1.6)	(4)	(0.7)
Retail – current year	$ 318	(0.3)%	$ 596	(1.0)%

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters" of Gulf Power in Item 7 and Note 1 to the financial statements of Gulf Power under "Revenues" and Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters" in Item 8 of the Form 10-K for additional information regarding Gulf Power's retail base rate case and cost recovery clauses, including Gulf Power's fuel cost recovery, purchased power capacity recovery, environmental cost recovery, and energy conservation cost recovery clauses.

Revenues associated with changes in rates and pricing increased in the second quarter and year-to-date 2017 when compared to the corresponding periods in 2016 primarily due to an increase in retail base revenues, as well as an increase in environmental cost recovery effective November 2016 resulting from Gulf Power's ownership of Plant Scherer Unit 3 being rededicated to retail service.

Revenues attributable to changes in sales decreased in the second quarter and year-to-date 2017 when compared to the corresponding periods in 2016 . Weather-adjusted KWH sales to residential and commercial customers decreased 1.2% and 1.3%, respectively, for the second quarter 2017 and 1.3% and 1.0%, respectively, for year-to-date 2017 due to lower customer usage primarily resulting from efficiency improvements in appliances and lighting, partially offset by customer growth. KWH sales to industrial customers decreased 2.7% and 5.6% for the second quarter and year-to-date 2017 , respectively, primarily due to changes in customers' operations. The year-to-date 2017 decrease also reflects increased customer co-generation.

Fuel and other cost recovery revenues decreased in the second quarter and year-to-date 2017 when compared to the corresponding periods in 2016 , primarily due to lower fuel, purchased power capacity, and energy conservation recoverable costs, partially offset by higher environmental recoverable costs. Fuel and other cost recovery provisions include fuel expenses, the energy component of purchased power costs, purchased power capacity costs, and the difference between projected and actual costs and revenues related to energy conservation and environmental compliance. See Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Cost Recovery Clauses – Retail Fuel Cost Recovery" in Item 8 of the Form 10-K for additional information.

Wholesale Revenues – Affiliates

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(5)	(33.3)	$11	30.6

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the IIC, as approved by the FERC. These transactions do not have a significant impact on earnings since the revenue related to these energy sales generally offsets the cost of energy sold.

In the second quarter 2017 , wholesale revenues from sales to affiliates were $10 million compared to $15 million for the corresponding period in 2016 . The decrease was primarily due to a 40.6% decrease in KWH sales due to decreased generation as a result of milder weather reducing Southern Company system loads.

For year-to-date 2017 , wholesale revenues from sales to affiliates were $47 million compared to $36 million for the corresponding period in 2016 . The increase was primarily due to a 17.2% increase in KWH sales as a result of supporting Southern Company system transmission reliability and a 10.0% increase in the price of energy due to higher natural gas prices.

Fuel and Purchased Power Expenses

	Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
	(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
Fuel	$ (19)	(17.8)	$ (5)	(2.5)
Purchased power – non-affiliates	3	9.4	5	8.1
Purchased power – affiliates	5	125.0	6	120.0
Total fuel and purchased power expenses	$ (11)		$ 6	

In the second quarter 2017 , total fuel and purchased power expenses were $132 million compared to $143 million for the corresponding period in 2016 . The decrease was primarily the result of a $21 million net decrease related to the volume of KWHs generated and purchased due to milder weather in 2017 reducing demand, partially offset by an $11 million net increase due to the higher average cost of fuel associated with purchased power.

For year-to-date 2017 , total fuel and purchased power expenses were $274 million compared to $268 million for the corresponding period in 2016 . The increase was primarily the result of a $16 million net increase related to the higher average cost of fuel and purchased power resulting from higher natural gas prices, partially offset by a $10 million net decrease related to the volume of KWHs generated and purchased due to milder weather in 2017 reducing demand.

Fuel and purchased power transactions do not have a significant impact on earnings since energy and capacity expenses are generally offset by energy and capacity revenues through Gulf Power's fuel and purchased power capacity cost recovery clauses and long-term wholesale contracts. See Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Cost Recovery Clauses – Retail Fuel Cost Recovery" and " – Purchased Power Capacity Recovery" in Item 8 of the Form 10-K for additional information.

Details of Gulf Power's generation and purchased power were as follows:

	Second Quarter 2017	Second Quarter 2016	**Year-to-Date 2017**	Year-to-Date 2016
Total generation *(in millions of KWHs)*	**1,898**	2,064	**4,220**	3,880
Total purchased power *(in millions of KWHs)*	**1,218**	1,629	**2,676**	3,389
Sources of generation *(percent)* –				
Coal	**50**	54	**52**	48
Gas	**50**	46	**48**	52
Cost of fuel, generated *(in cents per net KWH)* –				
Coal	**3.17**	4.14	**3.23**	4.05
Gas	**3.88**	4.11	**3.54**	3.92
Average cost of fuel, generated *(in cents per net KWH)*	**3.53**	4.12	**3.38**	3.98
Average cost of purchased power *(in cents per net KWH)* (*)	**5.37**	3.50	**4.93**	3.35

(*) Average cost of purchased power includes fuel purchased by Gulf Power for tolling agreements where power is generated by the provider.

Fuel

In the second quarter 2017 , fuel expense was $88 million compared to $107 million for the corresponding period in 2016 . The decrease was primarily due to a 14.3% decrease in the average cost of fuel resulting from lower coal and natural gas prices and a 15.3% decrease in the volume of KWHs generated by Gulf Power's coal-fired generation resources due to milder weather reducing demand.

For year-to-date 2017 , fuel expense was $196 million compared to $201 million for the corresponding period in 2016 . The decrease was primarily due to a 15.1% decrease in the average cost of fuel resulting from lower coal and natural gas prices, partially offset by an 8.8% increase in the volume of KWHs generated by Gulf Power's coal-fired and gas-fired generation resources due to Southern Company system reliability requirements.

Purchased Power – Non-Affiliates

In the second quarter 2017 , purchased power expense from non-affiliates was $35 million compared to $32 million for the corresponding period in 2016 . The increase was primarily due to a 68.7% increase in the average cost per KWH purchased primarily resulting from higher natural gas prices, partially offset by a 37.9% decrease in the volume of KWHs purchased due to a planned outage of an external generation resource under a PPA.

For year-to-date 2017 , purchased power expense from non-affiliates was $67 million compared to $62 million for the corresponding period in 2016 . The increase was primarily due to a 50.0% increase in the average cost per KWH purchased primarily resulting from higher natural gas prices, partially offset by a 25.6% decrease in the volume of KWHs purchased due to a planned outage of an external generation resource under a PPA.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation.

Purchased Power – Affiliates

In the second quarter 2017 , purchased power expense from affiliates was $9 million compared to $4 million for the corresponding period in 2016 . The increase was primarily due to a 66.1% increase in the volume of KWHs purchased due to availability of power pool resources at lower cost compared to Gulf Power generation.

For year-to-date 2017 , purchased power expense from affiliates was $11 million compared to $5 million for the corresponding period in 2016 . The increase was primarily due to a 22.9% increase in the volume of KWHs

purchased due to availability of power pool resources at lower cost compared to Gulf Power generation and a 67.1% increase in the average cost per KWH purchased primarily resulting from increased natural gas prices.

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

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$10	13.0	$16	10.3

In the second quarter 2017 , other operations and maintenance expenses were $87 million compared to $77 million for the corresponding period in 2016 . For year-to-date 2017 , other operations and maintenance expenses were $171 million compared to $155 million for the corresponding period in 2016 . The increases were primarily due to higher expenses at generation facilities associated with routine and planned maintenance.

Depreciation and Amortization

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(7)	(16.7)	$(27)	(33.8)

In the second quarter 2017 , depreciation and amortization was $35 million compared to $42 million for the corresponding period in 2016 . For year-to-date 2017 , depreciation and amortization was $53 million compared to $80 million for the corresponding period in 2016 . The decreases were primarily due to $8 million and $28 million more of a reduction in depreciation, as authorized in a settlement agreement approved by the Florida PSC in 2013 (2013 Rate Case Settlement Agreement), in the second quarter and year-to-date 2017 , respectively, compared to the corresponding periods in 2016 . See Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Retail Base Rate Case" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under " Regulatory Matters – Gulf Power – Retail Base Rate Cases " herein for additional information.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Gulf Power's future earnings potential. The level of Gulf Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Gulf Power's business of providing electric service. These factors include Gulf Power'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 driven primarily by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies due to changes in the minimum allowable equipment efficiencies along with the continuation of changes in customer behavior. Earnings are subject to a variety of other factors. These factors include weather, competition, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in Gulf Power's service territory. Demand for electricity is primarily driven by economic growth. The pace of economic growth and electricity demand may be affected by changes in regional and global economic conditions, which may impact future earnings. Current proposals related to potential federal tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals is dependent on the final form of any legislation enacted and the related transition rules and cannot be determined at this time, but could have a material impact on Gulf Power's financial statements. For additional information relating to these issues, see RISK FACTORS in Item

1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Gulf Power in Item 7 of the Form 10-K.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in retail rates or through long-term wholesale agreements on a timely basis or through market-based contracts. The State of Florida has statutory provisions that allow a utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Gulf Power's current long-term wholesale agreements contain provisions that permit charging the customer with costs incurred as a result of changes in environmental laws and regulations. The full impact of any such legislative or regulatory changes cannot be determined at this time. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are completed. Further, higher costs that are recovered through regulated rates or long-term wholesale agreements could contribute to reduced demand for electricity as well as impact the cost competitiveness of wholesale capacity, which could negatively affect results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters," "Retail Regulatory Matters – Cost Recovery Clauses – Environmental Cost Recovery," and "Other Matters" of Gulf Power in Item 7 and Note 3 to the financial statements of Gulf Power under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

Environmental Statutes and Regulations

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Gulf Power in Item 7 of the Form 10-K for additional information regarding the final effluent guidelines rule and the final rule revising the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs.

On April 25, 2017, the EPA published a notice announcing it would reconsider the effluent guidelines rule, which had been finalized in November 2015. On June 6, 2017, the EPA proposed a rule establishing a stay of the compliance deadlines for certain effluent limitations and pretreatment standards under the rule.

On June 27, 2017, the EPA and the U.S. Army Corps of Engineers proposed to rescind the final rule that revised the regulatory definition of waters of the U.S. for all CWA programs. The final rule has been stayed since October 2015 by the U.S. Court of Appeals for the Sixth Circuit.

The ultimate outcome of these matters cannot be determined at this time.

Global Climate Issues

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" of Gulf Power in Item 7 of the Form 10-K for additional information.

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. The executive order specifically directs the EPA to review the Clean Power Plan and final greenhouse gas emission standards for new, modified, and reconstructed electric generating units and, if appropriate, take action to suspend, revise, or rescind those rules.

On June 1, 2017, the U.S. President announced that the United States will withdraw from the non-binding Paris Agreement and begin renegotiation of its terms.

The ultimate outcome of these matters cannot be determined at this time.

FERC Matters

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters" of Gulf Power in Item 7 of the Form 10-K for additional information regarding the traditional electric operating companies' and Southern Power's market power proceeding and amendment to their market-rate tariff.

On May 17, 2017, the FERC accepted the traditional electric operating companies' (including Gulf Power's) and Southern Power's compliance filing accepting the terms of the FERC's February 2, 2017 order regarding an amendment by the traditional electric operating companies (including Gulf Power) and Southern Power to their market-based rate tariff. While the FERC's order references the traditional electric operating companies' (including Gulf Power's) and Southern Power's market power proceeding, it remains a separate, ongoing matter.

Retail Regulatory Matters

Gulf Power's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. Gulf Power's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through base rates. See Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters" in Item 8 of the Form 10-K for additional information.

Retail Base Rate Cases

The 2013 Rate Case Settlement Agreement authorized Gulf Power to reduce depreciation and record a regulatory asset up to $62.5 million from January 2014 through June 2017. In any given month, such depreciation reduction could not exceed the amount necessary for the retail ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized retail ROE range then in effect. For 2014 and 2015, Gulf Power recognized reductions in depreciation of $8.4 million and $20.1 million, respectively. No net reduction in depreciation was recorded in 2016. In the first six months of 2017 , Gulf Power recognized the remaining allowable reductions in depreciation totaling $34.0 million.

On April 4, 2017, the Florida PSC approved the 2017 Rate Case Settlement Agreement among Gulf Power and three intervenors with respect to Gulf Power's request to increase retail base rates. Under the terms of the 2017 Rate Case Settlement Agreement, Gulf Power increased rates effective with the first billing cycle in July 2017 to provide an annual overall net customer impact of approximately $54.3 million. The net customer impact consists of a $62.0 million increase in annual base revenues less an annual equivalent credit of approximately $7.7 million for 2017 for certain wholesale revenues to be provided through December 2019 through the purchased power capacity cost recovery clause. In addition, Gulf Power continued its authorized retail ROE midpoint (10.25%) and range (9.25% to 11.25%), is deemed to have an equity ratio of 52.5% for all retail regulatory purposes, and implemented new dismantlement accruals effective July 1, 2017. Gulf Power will also begin amortizing the regulatory asset associated with the investment balances remaining after the retirement of Plant Smith Units 1 and 2 over 15 years effective January 1, 2018 and will implement new depreciation rates effective January 1, 2018. The 2017 Rate Case Settlement Agreement also resulted in a $32.5 million write-down of Gulf Power's ownership of Plant Scherer Unit 3, which was recorded in the first quarter 2017. The remaining issues related to the inclusion of Gulf Power's investment in Plant Scherer Unit 3 in retail rates have been resolved as a result of the 2017 Rate Case Settlement Agreement, including recoverability of certain costs associated with the ongoing ownership and operation of the unit through the environmental cost recovery clause rate approved by the Florida PSC in November 2016.

Cost Recovery Clauses

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Cost Recovery Clauses" of Gulf Power in Item 7 and Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Cost Recovery Clauses" in Item 8 of the Form 10-K for additional information regarding Gulf Power's recovery of retail costs through various regulatory clauses and accounting

orders. Gulf Power has four regulatory clauses which are approved by the Florida PSC. See Note (B) to the Condensed Financial Statements herein for additional information.

As discussed previously, the 2017 Rate Case Settlement Agreement resolved the remaining issues related to Gulf Power's inclusion of certain costs associated with the ongoing ownership and operation of Plant Scherer Unit 3 in the environmental cost recovery clause and no adjustment to the environmental cost recovery clause rate approved by the Florida PSC in November 2016 was made.

Other Matters

Gulf Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Gulf Power is subject to certain claims and legal actions arising in the ordinary course of business. Gulf Power's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions , CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation against Gulf Power cannot be predicted at this time; however, for current proceedings not specifically reported in Note (B) to the Condensed Financial Statements herein , management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Gulf Power's financial statements. See Note (B) to the Condensed Financial Statements herein 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

Gulf Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Gulf Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Gulf Power'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. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Gulf Power in Item 7 of the Form 10-K for a complete discussion of Gulf Power's critical accounting policies and estimates related to Utility Regulation, Asset Retirement Obligations, Pension and Other Postretirement Benefits, and Contingent Obligations.

Recently Issued Accounting Standards

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 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.

While Gulf Power expect s most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of all revenue arrangements. The majority of Gulf Power'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 . Gulf Power expect s that the revenue from contracts with these customers will not result in a significant shift in the timing of revenue recognition for such sales .

Gulf Power's ongoing evaluation of other revenue streams and related contracts includes unregulated sales to customers. Some revenue arrangements are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed or presented separately from revenues under ASC 606 on Gulf Power's financial statements, if material. In addition, the power and utilities industry continues to evaluate other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). Although final implementation guidance has not been issued, Gulf Power expect s CIAC to be out of the scope of ASC 606.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. Gulf Power intend s to use the modified retrospective method of adoption effective January 1, 2018. Gulf Power has also elected to utilize practical expedients which allow 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, disclosures will include comparative information on 2018 financial statement line items under current guidance. While the adoption of ASC 606, including the cumulative-effect adjustment, is not expected to have a material impact on either the timing or amount of revenues recognized in Gulf Power's financial statements, Gulf Power will continue to evaluate the requirements, as well as any additional clarifying guidance that may be issued.

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 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 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 annual periods beginning after December 15, 2017, including interim periods within those annual periods. Gulf Power is currently evaluating the new standard. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in Gulf Power'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 adoption of ASU 2017-07 is not expected to have a material impact on Gulf Power's financial statements.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Overview" of Gulf Power in Item 7 of the Form 10-K for additional information. Gulf Power's financial condition remained stable at June 30, 2017 . Gulf Power intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit agreements to meet future capital and liquidity needs. See " Capital Requirements and Contractual Obligations ," " Sources of Capital ," and " Financing Activities " herein for additional information.

Net cash provided from operating activities totaled $124 million for the first six months of 2017 compared to $196 million for the corresponding period in 2016 . The $72 million decrease in net cash was primarily due to the timing of fossil fuel stock purchases, a federal income tax refund received in 2016, as well as decreases in cash flows associated with lower cost recovery clause rates. Net cash used for investing activities totaled $123 million in the first six months of 2017 primarily due to property additions to utility plant. Net cash used for financing activities totaled $12 million for the first six months of 2017 primarily due to the payment of short-term debt, redemptions of preference stock and long-term debt, and common stock dividend payments, partially offset by proceeds from

issuances of long-term debt and common stock. Cash flows from financing activities vary from period to period based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for the first six months of 2017 primarily reflect the financing activities described above. Other significant changes include a decrease in other cost of removal obligations, as authorized in the 2013 Settlement Agreement, and a decrease in property, plant, and equipment primarily due to the write-down of Gulf Power's ownership of Plant Scherer Unit 3. See "Financing Activities" herein and Note (B) to the Condensed Financial Statements under " Regulatory Matters – Gulf Power – Retail Base Rate Cases " herein for additional information.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Gulf Power in Item 7 of the Form 10-K for a description of Gulf Power's capital requirements for its construction program, including estimated capital expenditures to comply with existing environmental statutes and regulations, scheduled maturities of long-term debt, as well as related interest, leases, derivative obligations, purchase commitments, and trust funding requirements. Approximately $7 million will be required through June 30, 2018 to fund maturities of long-term debt. In addition, at June 30, 2017 , $20 million of Gulf Power's total fixed rate pollution control revenue bonds required to be remarketed over the next 12 months are classified as securities due within one year. See " Financing Activities " herein for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing generating units, to meet regulatory requirements; changes in the expected environmental compliance programs; changes in FERC rules and regulations; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

Sources of Capital

Gulf Power plans to obtain the funds required to meet its future capital needs from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, external security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Gulf Power in Item 7 of the Form 10-K for additional information.

Gulf Power's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as significant seasonal fluctuations in cash needs. Gulf Power has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet short-term liquidity needs, including its commercial paper program which is supported by bank credit facilities.

At June 30, 2017 , Gulf Power had approximately $45 million of cash and cash equivalents. Committed credit arrangements with banks at June 30, 2017 were as follows:

Expires						Executable Term Loans		Expires Within One Year	
2017	2018	2019	2020	Total	Unused	One Year	Two Years	Term Out	No Term Out
					(in millions)				
$ 30	$ 195	$ 25	$ 30	$ 280	$ 280	$ 45	$ —	$ —	$ 40

See Note 6 to the financial statements of Gulf Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under " Bank Credit Arrangements " herein for additional information.

Most of these bank credit arrangements contain covenants that limit debt levels and contain cross-acceleration provisions to other indebtedness (including guarantee obligations) of Gulf Power. Such cross-acceleration provisions to other indebtedness would trigger an event of default if Gulf Power defaulted on indebtedness, the payment of which was then accelerated. At June 30, 2017 , Gulf Power 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, Gulf Power expects to renew or replace its bank credit arrangements, as needed, prior to expiration. In connection therewith, Gulf Power may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

Most of the unused credit arrangements with banks are allocated to provide liquidity support to Gulf Power's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of June 30, 2017 was approximately $82 million . In addition, at June 30, 2017 , Gulf Power had approximately $140 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

Gulf Power 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 Gulf Power and the other traditional electric operating companies. Proceeds from such issuances for the benefit of Gulf Power are loaned directly to Gulf Power. The obligations of each traditional electric operating company under these arrangements are several and there is no cross-affiliate credit support. Short-term borrowings are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Short-term Debt at June 30, 2017		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)
Commercial paper	$ 78	1.5%	$ 20	1.4%	$ 78
Short-term bank debt	—	—%	53	1.7%	100
Total	$ 78	1.5%	$ 73	1.6%	

(*) Average and maximum amounts are based upon daily balances during the three -month period ended June 30, 2017 .

Gulf Power believes the need for working capital can be adequately met by utilizing the commercial paper program, lines of credit, short-term bank loans, and operating cash flows.

Credit Rating Risk

At June 30, 2017 , Gulf Power did not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, transmission, and energy price risk management.

The maximum potential collateral requirements under these contracts at June 30, 2017 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 167
Below BBB- and/or Baa3	$ 570

Included in these amounts are certain agreements that could require collateral in the event that Alabama Power or Georgia Power has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of Gulf Power 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 Gulf Power) from stable to negative.

Market Price Risk

Gulf Power's market risk exposure relative to interest rate changes for the second quarter and year-to-date 2017 has not changed materially compared to the December 31, 2016 reporting period. Gulf Power's exposure to market volatility in commodity fuel prices and prices of electricity with respect to its wholesale generating capacity is limited because its long-term sales agreement shifts substantially all fuel cost responsibility to the purchaser.

In connection with the 2017 Rate Case Settlement Agreement, Gulf Power recorded a $32.5 million write-down of Gulf Power's ownership of Plant Scherer Unit 3 in the first quarter 2017 to resolve the inclusion of Gulf Power's investment in Plant Scherer Unit 3 in retail rates and no adjustment to the environmental cost recovery clause rate approved by the Florida PSC in November 2016 was made. The 2017 Rate Case Settlement Agreement provides that 100% of Gulf Power's ownership of Plant Scherer Unit 3 will be included in retail rates. This resolved the market price risk concern around Gulf Power's uncontracted wholesale generating capacity related to Plant Scherer Unit 3. See FUTURE EARNINGS POTENTIAL – " Retail Regulatory Matters " herein for additional information.

The Florida PSC extended the moratorium on Gulf Power's fuel-hedging program through January 1, 2021 in connection with the 2017 Rate Case Settlement Agreement. The moratorium does not have an impact on the recovery of existing hedges entered into under the previously-approved hedging program.

For additional discussion of Gulf Power's market risks, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of Gulf Power in Item 7 of the Form 10-K.

Financing Activities

In January 2017, Gulf Power issued 1,750,000 shares of common stock to Southern Company and realized proceeds of $175 million. The proceeds were used for general corporate purposes, including Gulf Power's continuous construction program.

In March 2017, Gulf Power extended the maturity of a $100 million short-term floating rate bank loan bearing interest based on one-month LIBOR from April 2017 to October 2017 and subsequently repaid the loan in May 2017.

In May 2017, Gulf Power issued $300 million aggregate principal amount of Series 2017A 3.30% Senior Notes due May 30, 2027. The proceeds, together with other funds, were used to repay at maturity $85 million aggregate principal amount of Series 2007A 5.90% Senior Notes due June 15, 2017; to repay outstanding commercial paper borrowings; to repay a $100 million short-term floating rate bank loan, as discussed above; and to redeem 550,000 shares ($55 million aggregate liquidation amount) of 6.00% Series Preference Stock, 450,000 shares ($45 million aggregate liquidation amount) of Series 2007A 6.45% Preference Stock, and 500,000 shares ($50 million aggregate liquidation amount) of Series 2013A 5.60% Preference Stock.

In addition to any financings that may be necessary to meet capital requirements, contractual obligations, and storm recovery, Gulf Power 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.

MISSISSIPPI POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	**2017**	2016
	(in millions)		*(in millions)*	
Operating Revenues:				
Retail revenues	**$ 222**	$ 206	**$ 422**	$ 389
Wholesale revenues, non-affiliates	**62**	60	**124**	120
Wholesale revenues, affiliates	**15**	7	**20**	16
Other revenues	**4**	4	**9**	8
Total operating revenues	**303**	277	**575**	533
Operating Expenses:				
Fuel	**102**	81	**180**	157
Purchased power, non-affiliates	**2**	1	**3**	1
Purchased power, affiliates	**4**	4	**11**	9
Other operations and maintenance	**70**	68	**144**	136
Depreciation and amortization	**41**	45	**81**	84
Taxes other than income taxes	**26**	25	**52**	50
Estimated loss on Kemper IGCC	**3,012**	81	**3,120**	134
Total operating expenses	**3,257**	305	**3,591**	571
Operating Loss	**(2,954)**	(28)	**(3,016)**	(38)
Other Income and (Expense):				
Allowance for equity funds used during construction	**36**	30	**71**	59
Interest expense, net of amounts capitalized	**(17)**	(15)	**(37)**	(31)
Other income (expense), net	**1**	(1)	**1**	(3)
Total other income and (expense)	**20**	14	**35**	25
Loss Before Income Taxes	**(2,934)**	(14)	**(2,981)**	(13)
Income taxes (benefit)	**(881)**	(17)	**(908)**	(27)
Net Income (Loss)	**(2,053)**	3	**(2,073)**	14
Dividends on Preferred Stock	**1**	1	**1**	1
Net Income (Loss) After Dividends on Preferred Stock	**$ (2,054)**	$ 2	**$ (2,074)**	$ 13

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	**2017**	2016
	(in millions)		*(in millions)*	
Net Income (Loss)	**$ (2,053)**	$ 3	**$ (2,073)**	$ 14
Other comprehensive income (loss)				
Qualifying hedges:				
Changes in fair value, net of tax of $-, $-, $-, and $-, respectively	**—**	—	**1**	—
Total other comprehensive income (loss)	**—**	—	**1**	—
Comprehensive Income (Loss)	**$ (2,053)**	$ 3	**$ (2,072)**	$ 14

The accompanying notes as they relate to Mississippi Power are an integral part of these condensed financial statements.

MISSISSIPPI POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Six Months Ended June 30,	
	2017	2016
	(in millions)	
Operating Activities:		
Net income (loss)	**$ (2,073)**	$ 14
Adjustments to reconcile net income (loss) to net cash provided from operating activities —		
Depreciation and amortization, total	**94**	82
Deferred income taxes	**(860)**	(16)
Allowance for equity funds used during construction	**(71)**	(59)
Estimated loss on Kemper IGCC	**3,120**	134
Other, net	**(11)**	(8)
Changes in certain current assets and liabilities —		
-Receivables	**(15)**	15
-Fossil fuel stock	**21**	6
-Other current assets	**(10)**	31
-Accounts payable	**(20)**	(12)
-Accrued taxes	**—**	20
-Accrued compensation	**(17)**	(12)
-Over recovered regulatory clause revenues	**(30)**	4
-Customer liability associated with Kemper refunds	**—**	(69)
-Other current liabilities	**7**	7
Net cash provided from operating activities	**135**	137
Investing Activities:		
Property additions	**(337)**	(403)
Construction payables	**(19)**	(11)
Government grant proceeds	**—**	137
Other investing activities	**(5)**	(19)
Net cash used for investing activities	**(361)**	(296)
Financing Activities:		
Decrease in notes payable, net	**(10)**	—
Proceeds —		
Capital contributions from parent company	**1,001**	226
Long-term debt to parent company	**40**	200
Other long-term debt	**—**	900
Short-term borrowings	**4**	—
Redemptions —		
Short-term borrowings	**—**	(475)
Long-term debt to parent company	**(591)**	(225)
Other long-term debt	**(300)**	(425)
Other financing activities	**(2)**	(3)
Net cash provided from financing activities	**142**	198
Net Change in Cash and Cash Equivalents	**(84)**	39
Cash and Cash Equivalents at Beginning of Period	**224**	98
Cash and Cash Equivalents at End of Period	**$ 140**	$ 137
Supplemental Cash Flow Information:		
Cash paid (received) during the period for —		
Interest (paid $53 and $49, net of $27 and $23 capitalized for 2017 and 2016, respectively)	**$ 26**	$ 26
Income taxes, net	**(93)**	(122)
Noncash transactions — Accrued property additions at end of period	**59**	94

The accompanying notes as they relate to Mississippi Power are an integral part of these condensed financial statements.

MISSISSIPPI POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Assets	At June 30, 2017	At December 31, 2016
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 140**	$ 224
Receivables —		
Customer accounts receivable	**33**	29
Unbilled revenues	**42**	42
Income taxes receivable, current	**544**	544
Other accounts and notes receivable	**25**	14
Affiliated	**20**	15
Fossil fuel stock	**20**	100
Materials and supplies	**44**	76
Other regulatory assets, current	**114**	115
Other current assets	**2**	8
Total current assets	**984**	1,167
Property, Plant, and Equipment:		
In service	**4,826**	4,865
Less: Accumulated provision for depreciation	**1,283**	1,289
Plant in service, net of depreciation	**3,543**	3,576
Construction work in progress	**56**	2,545
Total property, plant, and equipment	**3,599**	6,121
Other Property and Investments	**22**	12
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**61**	361
Other regulatory assets, deferred	**441**	518
Accumulated deferred income taxes	**404**	—
Other deferred charges and assets	**20**	56
Total deferred charges and other assets	**926**	935
Total Assets	**$ 5,531**	$ 8,235

The accompanying notes as they relate to Mississippi Power are an integral part of these condensed financial statements.

MISSISSIPPI POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	At June 30, 2017	At December 31, 2016
	(in millions)	
Current Liabilities:		
Securities due within one year —		
Parent	$ —	$ 551
Other	1,028	78
Notes payable	17	23
Accounts payable —		
Affiliated	54	62
Other	109	135
Customer deposits	16	16
Accrued taxes	97	99
Unrecognized tax benefits	385	383
Accrued interest	52	46
Accrued compensation	25	42
Asset retirement obligations, current	21	32
Over recovered regulatory clause liabilities	21	51
Other current liabilities	89	20
Total current liabilities	1,914	1,538
Long-term Debt	1,169	2,424
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	—	756
Employee benefit obligations	111	115
Asset retirement obligations, deferred	149	146
Other cost of removal obligations	173	170
Other regulatory liabilities, deferred	80	84
Other deferred credits and liabilities	29	26
Total deferred credits and other liabilities	542	1,297
Total Liabilities	3,625	5,259
Redeemable Preferred Stock	33	33
Common Stockholder's Equity:		
Common stock, without par value —		
Authorized — 1,130,000 shares		
Outstanding — 1,121,000 shares	38	38
Paid-in capital	4,527	3,525
Accumulated deficit	(2,689)	(616)
Accumulated other comprehensive loss	(3)	(4)
Total common stockholder's equity	1,873	2,943
Total Liabilities and Stockholder's Equity	$ 5,531	$ 8,235

The accompanying notes as they relate to Mississippi Power are an integral part of these condensed financial statements.

MISSISSIPPI POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

SECOND QUARTER 2017 vs. SECOND QUARTER 2016
AND
YEAR-TO-DATE 2017 vs. YEAR-TO-DATE 2016

OVERVIEW

Mississippi Power operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located within the State of Mississippi and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of Mississippi Power's business of providing electric service. These factors include Mississippi Power's ability to maintain and grow energy sales and to operate in a constructive regulatory environment that provides timely recovery of prudently-incurred costs. These costs include those related to the Kemper County energy facility, projected long-term demand growth, reliability, fuel, and stringent environmental standards, as well as ongoing capital expenditures required for maintenance and restoration following major storms. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge Mississippi Power for the foreseeable future.

The Kemper IGCC was approved by the Mississippi PSC in the 2010 CPCN proceedings, subject to a construction cost cap of $2.88 billion, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (Initial DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions). The combined cycle and associated common facilities portion of the Kemper IGCC were placed in service in August 2014.

In December 2015, the Mississippi PSC issued an order (In-Service Asset Rate Order), based on a stipulation (2015 Stipulation) between Mississippi Power and the Mississippi Public Utilities Staff (MPUS), authorizing rates that provide for the recovery of approximately $126 million annually related to the combined cycle and associated common facilities portion of Kemper IGCC assets previously placed in service. As required by the In-Service Asset Rate Order, on June 5, 2017, Mississippi Power made a rate filing requesting to adjust the amortization schedules of the regulatory assets reviewed and determined prudent in a manner that would not change customer rates or annual revenues. On June 28, 2017, the Mississippi PSC suspended this filing. On July 6, 2017, the Mississippi PSC issued an order requiring Mississippi Power to establish a regulatory liability account to maintain current rates related to the Kemper IGCC following the July 2017 completion of the amortization period for certain regulatory assets approved in the In-Service Asset Rate Order that would allow for subsequent refund if the Mississippi PSC deems the rates unjust and unreasonable.

The remainder of the plant includes the gasifiers and the gas clean-up facilities. The initial production of syngas began on July 14, 2016 for gasifier "B" and on September 13, 2016 for gasifier "A." Mississippi Power achieved integrated operation of both gasifiers on January 29, 2017, including the production of electricity from syngas in both combustion turbines. During testing, the plant produced and captured CO_2, and produced sulfuric acid and ammonia, each of acceptable quality under the related off-take agreements. However, Mississippi Power experienced numerous challenges during the extended start-up process to achieve integrated operation of the gasifiers on a sustained basis. Most recently, in May 2017, after achieving these milestones, Mississippi Power determined that a critical system component, the syngas coolers, would need replacement sooner than originally planned, which would require significant lead time and significant cost. In addition, the long-term natural gas price forecast has decreased significantly and the estimated cost of operating and maintaining the facility during the first five full years of operations increased significantly since certification.

On June 21, 2017, the Mississippi PSC stated its intent to issue an order (which occurred on July 6, 2017) directing Mississippi Power to pursue a settlement under which the Kemper County energy facility would be operated as a

natural gas plant, rather than an IGCC plant, and address all issues associated with the Kemper IGCC (Kemper Settlement Order). The Kemper Settlement Order established a new docket for the purposes of pursuing a global settlement of costs of the Kemper IGCC (Kemper IGCC Settlement Docket). The Mississippi PSC requested any such proposed settlement agreement reflect: (i) at a minimum, no rate increase to Mississippi Power customers (with a rate reduction focused on residential customers encouraged); (ii) removal of all cost risk to customers associated with the Kemper IGCC gasifier and related assets; and (iii) modification or amendment of the CPCN for the Kemper IGCC to allow only for ownership and operation of a natural gas facility. The Kemper Settlement Order provides that any related settlement agreement be filed within 45 days from the effective date of the Kemper Settlement Order. If a settlement agreement is filed, a hearing will be set 45 days from the date of the settlement's filing, and the appropriate scheduling order will be established.

Although the ability to achieve a negotiated settlement is uncertain, Mississippi Power intends to pursue any available settlement alternatives. In addition, the Kemper Settlement Order provides that, in the event a settlement agreement is not reached, the Mississippi PSC reserves its right to take any appropriate steps, including issuing an order to show cause as to why the CPCN for the Kemper IGCC should not be revoked.

On June 28, 2017, Mississippi Power notified the Mississippi PSC that it would begin a process to suspend operations and start-up activities on the gasifier portion of the Kemper IGCC, given the uncertainty as to the future of the gasifier portion of the Kemper IGCC. Mississippi Power expects to continue to operate the combined cycle portion of the Kemper IGCC as it has done since August 2014.

At the time of project suspension, the total cost estimate for the Kemper IGCC was approximately $7.38 billion, including approximately $5.95 billion of costs subject to the construction cost cap, and was net of the $137 million in additional grants from the DOE received on April 8, 2016 (Additional DOE Grants). Mississippi Power recorded pre-tax charges to income for revisions to the cost estimate subject to the construction cost cap totaling $196 million ($121 million after tax) in the second quarter through May 31, 2017 and a total of $305 million ($188 million after tax) for year-to-date through May 31, 2017. In the aggregate, Mississippi Power incurred charges of $3.07 billion ($1.89 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through May 31, 2017. The May 31, 2017 cost estimate included approximately $175 million of estimated costs to be incurred beyond the then-estimated in-service date of June 30, 2017 that were expected to be subject to the $2.88 billion cost cap.

At June 30, 2017, approximately $3.3 billion in actual Kemper IGCC costs were not reflected in Mississippi Power's retail and wholesale rates, of which $0.5 billion was related to the combined cycle and associated facilities and $2.8 billion was related to the gasification portions of the Kemper IGCC.

While the ultimate disposition of the gasification portions of the Kemper IGCC remains subject to the Mississippi PSC's jurisdiction, including the potential resolution of the matters addressed in the Kemper Settlement Order, given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility, cost recovery of the gasification portions is no longer probable; therefore, Mississippi Power recorded an additional charge to income in June 2017 of $2.8 billion ($2.0 billion after tax), which includes estimated costs associated with the gasification portions of the plant and lignite mine. In the event the gasification portions of the project are ultimately canceled, additional pre-tax costs currently estimated at approximately $100 million to $200 million are expected to be incurred.

Total pre-tax charges to income for the estimated probable losses on the Kemper IGCC were $3.0 billion ($2.1 billion after tax) for the second quarter 2017 and $3.1 billion ($2.2 billion after tax) for the six months ended June 30, 2017. In the aggregate, since the Kemper IGCC project started, Mississippi Power has incurred charges of $6.0 billion ($3.9 billion after tax) through June 30, 2017.

As of June 30, 2017, Mississippi Power has recorded a total of approximately $1.3 billion in costs associated with the combined cycle portion of the Kemper IGCC including transmission and related regulatory assets, of which $0.8 billion is included in retail and wholesale rates. The $0.5 billion not included in current rates includes costs in excess of the original 2010 estimate for the combined cycle portion of the facility, as well as the 15% that was

previously contracted to SMEPA. Mississippi Power has calculated the revenue requirements resulting from these remaining costs, using reasonable assumptions for amortization periods, and expects them to be recovered through rates consistent with the Mississippi PSC's requested settlement conditions. The ultimate outcome will be determined by the Mississippi PSC in the Kemper IGCC Settlement Docket proceedings.

For additional information on the Kemper IGCC, including information on the project economic viability analysis, pending lawsuits, and an ongoing SEC investigation, see Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and FUTURE EARNINGS POTENTIAL – " Integrated Coal Gasification Combined Cycle " and "Other Matters" and Note (B) to the Condensed Financial Statements under " Integrated Coal Gasification Combined Cycle " herein.

In June 2017, Southern Company made equity contributions totaling $1.0 billion to Mississippi Power. Mississippi Power used a portion of the proceeds to (i) prepay $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan; (ii) repay $591 million of the outstanding principal amount of promissory notes to Southern Company; and (iii) repay $10 million of the outstanding principal amount of bank loans.

Mississippi Power's financial statement presentation contemplates continuation of Mississippi Power as a going concern as a result of Southern Company's anticipated ongoing financial support of Mississippi Power. For additional information, see Notes 1 and 6 to the financial statements of Mississippi Power under "Recently Issued Accounting Standards" and "Going Concern," respectively, in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Going Concern" herein.

In addition to the rate recovery of the Kemper County energy facility, Mississippi Power continues to focus on several key performance indicators. In recognition that Mississippi Power's long-term financial success is dependent upon how well it satisfies its customers' needs, Mississippi Power's retail base rate mechanism, PEP, includes performance indicators that directly tie customer service indicators to Mississippi Power's allowed ROE. Mississippi Power also focuses on broader measures of customer satisfaction, plant availability, system reliability, and net income after dividends on preferred stock.

RESULTS OF OPERATIONS

Net Income (Loss)

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(2,056)	N/M	$(2,087)	N/M

N/M - Not meaningful

In the second quarter and year-to-date 2017, Mississippi Power's net loss after dividends on preferred stock was $2.05 billion and $2.07 billion , respectively, compared to net income of $2 million and $13 million , respectively, for the corresponding periods in 2016 . In the second quarter and year-to-date 2017, the decrease in net income was related to higher pre-tax charges associated with the Kemper IGCC of $3.0 billion ($2.1 billion after tax) and $3.1 billion ($2.2 billion after tax), respectively, compared to pre-tax charges of $81 million ($50 million after tax) and $134 million ($83 million after tax), respectively, for the corresponding periods in 2016. The changes in net income were partially offset by a decrease in depreciation and amortization and increases in retail revenues, AFUDC equity, and income tax benefits.

See Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under " Integrated Coal Gasification Combined Cycle " herein for additional information.

Retail Revenues

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$16	7.8	$33	8.5

In the second quarter 2017 , retail revenues were $222 million compared to $206 million for the corresponding period in 2016 . For year-to-date 2017 , retail revenues were $422 million compared to $389 million for the corresponding period in 2016 .

Details of the changes in retail revenues were as follows:

	Second Quarter 2017		Year-to-Date 2017	
	(in millions)	*(% change)*	*(in millions)*	*(% change)*
Retail – prior year	$ 206		$ 389	
Estimated change resulting from –				
Rates and pricing	8	3.9	19	4.9
Sales growth (decline)	(2)	(0.9)	3	0.8
Weather	(2)	(1.0)	(7)	(1.8)
Fuel and other cost recovery	12	5.8	18	4.6
Retail – current year	$ 222	7.8 %	$ 422	8.5 %

Revenues associated with changes in rates and pricing increased in the second quarter and year-to-date 2017 when compared to the corresponding periods in 2016 primarily due to an ECO Plan rate increase implemented in the third quarter 2016, partially offset by an ECO Plan rate decrease implemented in the second quarter 2017.

Revenues attributable to changes in sales decreased for the second quarter 2017 when compared to the corresponding period in 2016 . Weather-adjusted KWH sales to residential customers decreased 2.7% due to lower customer usage. Weather-adjusted KWH sales to commercial customers decreased 0.8% due to lower customer usage, offset by customer growth. KWH sales to industrial customers decreased 1.3% primarily due to an unplanned outage by a large customer in 2017 and a decrease in the number of mid-size customers.

Revenues attributable to changes in sales increased for year-to-date 2017 when compared to the corresponding period in 2016 . Weather-adjusted KWH sales to residential and commercial customers decreased 0.7% and 0.5%, respectively, due to lower customer usage. KWH sales to industrial customers decreased 0.4% primarily due to an unplanned outage by a larger customer in 2017 and a decrease in the number of mid-size customers.

Fuel and other cost recovery revenues increased in the second quarter and year-to-date 2017 when compared to the corresponding periods in 2016 , primarily as a result of higher recoverable fuel costs. See " Fuel and Purchased Power Expenses " herein for additional information. Recoverable fuel costs include fuel and purchased power expenses reduced by the fuel portion of wholesale revenues from energy sold to customers outside Mississippi Power's service territory. Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the energy component of purchased power costs, and do not affect net income.

Wholesale Revenues – Non-Affiliates

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$2	3.3	$4	3.3

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of Mississippi Power's and the Southern Company system's generation, demand for

energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. In addition, Mississippi Power provides service under long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters" of Mississippi Power in Item 7 of the Form 10-K and – FUTURE EARNINGS POTENTIAL – "FERC Matters" herein for additional information.

In the second quarter and year-to-date 2017, wholesale revenues from sales to non-affiliates were $62 million and $124 million , respectively, compared to $60 million and $120 million for the corresponding periods in 2016 . The increases were due to increases in energy revenues of $4 million and $5 million in the second quarter and year-to-date 2017, respectively, primarily resulting from higher fuel prices, partially offset by decreases in base and capacity revenues of $2 million and $1 million, respectively, primarily due to milder weather resulting in lower sales.

Wholesale Revenues – Affiliates

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$8	N/M	$4	25.0

N/M - Not meaningful

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the IIC, as approved by the FERC. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

In the second quarter 2017 , wholesale revenues from sales to affiliates were $15 million compared to $7 million for the corresponding period in 2016 . The increase was due to a $6 million increase in KWH sales and a $2 million increase primarily due to higher natural gas prices.

For year-to-date 2017 , wholesale revenues from sales to affiliates were $20 million compared to $16 million for the corresponding period in 2016 . The increase was primarily due to higher natural gas prices.

Fuel and Purchased Power Expenses

	Second Quarter 2017 vs. Second Quarter 2016			Year-to-Date 2017 vs. Year-to-Date 2016		
		(change in millions)	*(% change)*		*(change in millions)*	*(% change)*
Fuel	$	21	25.9	$	23	14.6
Purchased power – non-affiliates		1	100.0		2	200.0
Purchased power – affiliates		—	—		2	22.2
Total fuel and purchased power expenses	$	22		$	27	

In the second quarter 2017 , total fuel and purchased power expenses were $108 million compared to $86 million for the corresponding period in 2016 . The increase was due to a $17 million increase in natural gas prices and a $5 million increase in the volume of KWHs generated and purchased.

For year-to-date 2017 , total fuel and purchased power expenses were $194 million compared to $167 million for the corresponding period in 2016 . The increase was due to a $34 million increase in natural gas prices, partially offset by a $7 million decrease in the volume of KWHs generated and 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 Mississippi Power's fuel cost recovery clause.

Details of Mississippi Power's generation and purchased power were as follows:

	Second Quarter 2017	Second Quarter 2016	**Year-to-Date 2017**	Year-to-Date 2016
Total generation *(in millions of KWHs)*	**3,927**	3,728	**7,088**	7,315
Total purchased power *(in millions of KWHs)* (*)	**121**	188	**362**	449
Sources of generation *(percent)* –				
Coal	**7**	5	**8**	8
Gas	**93**	95	**92**	92
Cost of fuel, generated *(in cents per net KWH)* –				
Coal	**3.61**	5.49	**3.46**	4.16
Gas	**2.73**	2.17	**2.69**	2.16
Average cost of fuel, generated *(in cents per net KWH)*	**2.79**	2.33	**2.76**	2.32
Average cost of purchased power *(in cents per net KWH)* (*)	**4.74**	2.55	**3.80**	2.33

(*) Includes energy produced during the test period for the Kemper IGCC, which is accounted for in accordance with FERC guidance.

Fuel

In the second quarter 2017 , total fuel expense was $102 million compared to $81 million for the corresponding period in 2016 . The increase was due to a 20% increase in the average cost of fuel per KWH generated, primarily due to a 26% higher cost of natural gas, and a 6% increase in the volume of KWHs generated.

For year-to-date 2017 , total fuel expense was $180 million compared to $157 million for the corresponding period in 2016 . The increase was due to a 19% increase in the average cost of fuel per KWH generated primarily due to a 25% higher cost of natural gas, partially offset by a 3% decrease in the volume of KWHs generated.

Purchased Power

Energy purchases will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Energy purchases from affiliates are made in accordance with the IIC, as approved by the FERC.

Other Operations and Maintenance Expenses

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$2	2.9	$8	5.9

For year-to-date 2017 , other operations and maintenance expenses were $144 million compared to $136 million for the corresponding period in 2016 . The increase was primarily associated with the Kemper IGCC in-service assets.

See FUTURE EARNINGS POTENTIAL – " Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2015 Rate Case " herein for additional information.

Depreciation and Amortization

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(4)	(8.9)	$(3)	(3.6)

In the second quarter 2017 , depreciation and amortization was $41 million compared to $45 million for the corresponding period in 2016 . For year-to-date 2017 , depreciation and amortization was $81 million compared to $84 million for the corresponding period in 2016 . The decreases were primarily related to changes in amortization and deferrals associated with regulatory assets.

See Note 1 to the financial statements of Mississippi Power under "Depreciation, Depletion, and Amortization" in Item 8 of the Form 10-K.

Estimated Loss on Kemper IGCC

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$2,931	N/M	$2,986	N/M

N/M - Not meaningful

Prior to the project suspension on June 28, 2017, estimated probable losses on the Kemper IGCC totaled $196 million and $305 million in the second quarter and year-to-date 2017 , respectively, compared to $81 million and $134 million in the second quarter and year-to-date 2016 , respectively. These losses reflected revisions of estimated costs expected to be incurred on the construction of the Kemper IGCC prior to project suspension in excess of the $2.88 billion cost cap established by the Mississippi PSC, net of the Initial DOE Grants and excluding the Cost Cap Exceptions.

While the ultimate disposition of the gasification portions of the Kemper IGCC remains subject to the Mississippi PSC's jurisdiction, including the potential resolution of the matters addressed in the Kemper Settlement Order, given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility, cost recovery of the gasification portions is no longer probable; therefore, Mississippi Power recorded an additional charge to income in June 2017 of $2.8 billion, which includes estimated costs associated with the gasification portions of the plant and lignite mine.

See Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and FUTURE EARNINGS POTENTIAL – " Integrated Coal Gasification Combined Cycle " and Note (B) to the Condensed Financial Statements under " Integrated Coal Gasification Combined Cycle " herein for additional information.

Allowance for Equity Funds Used During Construction

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$6	20.0	$12	20.3

In the second quarter 2017 , AFUDC equity was $36 million compared to $30 million for the corresponding period in 2016 . For year-to-date 2017 , AFUDC equity was $71 million compared to $59 million for the corresponding period in 2016 . The increases resulted from a higher AFUDC rate and an increase in Kemper IGCC CWIP subject to AFUDC prior to project suspension.

See Note 3 to the financial statements of Mississippi Power under "FERC Matters" and "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and FUTURE EARNINGS POTENTIAL – " Integrated

Coal Gasification Combined Cycle " and Note (B) to the Condensed Financial Statements under " FERC Matters " and " Integrated Coal Gasification Combined Cycle " herein for additional information regarding the Kemper IGCC.

Interest Expense, Net of Amounts Capitalized

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$2	13.3	$6	19.4

In the second quarter 2017 , interest expense, net of amounts capitalized was $17 million compared to $15 million , for the corresponding period in 2016 . For year-to-date 2017 , interest expense, net of amounts capitalized was $37 million compared to $31 million for the corresponding period in 2016 . The increases were primarily associated with the Kemper IGCC in-service assets.

See Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under " Integrated Coal Gasification Combined Cycle " herein for additional information.

Income Taxes (Benefit)

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(864)	N/M	$(881)	N/M

N/M - Not meaningful

In the second quarter 2017 , income tax benefit was $881 million compared to $17 million for the corresponding period in 2016 . For year-to-date 2017 , income tax benefit was $908 million compared to $27 million for the corresponding period in 2016 . The changes were primarily due to the estimated probable losses on the Kemper IGCC, net of the non-deductible AFUDC equity portion and the related state valuation allowances.

See Note (G) to the Condensed Financial Statements herein for additional information.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Mississippi Power's future earnings potential. The level of Mississippi Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Mississippi Power's business of providing electric service. These factors include Mississippi Power's ability to recover its prudently-incurred costs, including those related to the remainder of the Kemper County energy facility not included in current rates, in a timely manner during a time of increasing costs and its ability to prevail against legal challenges associated with the Kemper County energy facility. Future earnings will be driven primarily by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies and increasing volumes of electronic commerce transactions. Earnings are subject to a variety of other factors. These factors include weather, competition, developing new and maintaining existing energy contracts and associated load requirements with other utilities and other wholesale customers, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in Mississippi Power's service territory. Demand for electricity is primarily driven by economic growth. The pace of economic growth and electricity demand may be affected by changes in regional and global economic conditions, which may impact future earnings.

Current proposals related to potential federal tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals is dependent on the final form of any legislation enacted and the related

transition rules and cannot be determined at this time, but could have a material impact on Mississippi Power's financial statements.

For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Mississippi Power in Item 7 of the Form 10-K and Note (B) to the Condensed Financial Statements under " Integrated Coal Gasification Combined Cycle " herein for additional information.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis or through long-term wholesale agreements. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are completed. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

Environmental Statutes and Regulations

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Mississippi Power in Item 7 of the Form 10-K for additional information regarding the final effluent guidelines rule and the final rule revising the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs.

On April 25, 2017, the EPA published a notice announcing it would reconsider the effluent guidelines rule, which had been finalized in November 2015. On June 6, 2017, the EPA proposed a rule establishing a stay of the compliance deadlines for certain effluent limitations and pretreatment standards under the rule.

On June 27, 2017, the EPA and the U.S. Army Corps of Engineers proposed to rescind the final rule that revised the regulatory definition of waters of the U.S. for all CWA programs. The final rule has been stayed since October 2015 by the U.S. Court of Appeals for the Sixth Circuit.

The ultimate outcome of these matters cannot be determined at this time.

Global Climate Issues

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" of Mississippi Power in Item 7 of the Form 10-K for additional information.

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. The executive order specifically directs the EPA to review the Clean Power Plan and final greenhouse gas emission standards for new, modified, and reconstructed electric generating units and, if appropriate, take action to suspend, revise, or rescind those rules.

On June 1, 2017, the U.S. President announced that the United States will withdraw from the non-binding Paris Agreement and begin renegotiation of its terms.

The ultimate outcome of these matters cannot be determined at this time.

FERC Matters

Municipal and Rural Associations Tariff

See Note 3 to the financial statements of Mississippi Power under "FERC Matters" in Item 8 of the Form 10-K for additional information regarding a settlement agreement entered into by Mississippi Power regarding the establishment of a regulatory asset for Kemper IGCC-related costs. See Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under " Integrated Coal Gasification Combined Cycle " herein for information regarding the Kemper IGCC.

In March 2016, Mississippi Power reached a settlement agreement with its wholesale customers, which was subsequently approved by the FERC, for an increase in wholesale base revenues under the MRA cost-based electric tariff, primarily as a result of placing scrubbers for Plant Daniel Units 1 and 2 in service in 2015. The settlement agreement became effective for services rendered beginning May 1, 2016, resulting in an estimated annual revenue increase of $7 million under the MRA cost-based electric tariff. Additionally, under the settlement agreement, the tariff customers agreed to similar regulatory treatment for MRA tariff ratemaking as the treatment approved for retail ratemaking under the In-Service Asset Rate Order. This regulatory treatment primarily includes (i) recovery of the Kemper IGCC assets currently operational and providing service to customers and other related costs, (ii) amortization of the Kemper IGCC-related regulatory assets included in rates under the settlement agreement over the 36 months ending April 30, 2019, (iii) Kemper IGCC-related expenses included in rates under the settlement agreement no longer being deferred and charged to expense, and (iv) removing all of the Kemper IGCC CWIP from rate base with a corresponding increase in accrual of AFUDC. The additional resulting AFUDC totaled approximately $22 million through the suspension of Kemper IGCC start-up activities.

See Note (B) to the Condensed Financial Statements under " Integrated Coal Gasification Combined Cycle " herein for additional information.

Fuel Cost Recovery

Mississippi Power has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. At June 30, 2017, the amount of over-recovered wholesale MRA fuel costs included in the balance sheets was $7 million compared to $13 million at December 31, 2016. Over-recovered wholesale MB fuel costs included in the balance sheets were immaterial at June 30, 2017 and December 31, 2016.

See Note 3 to the financial statements of Mississippi Power under "FERC Matters – Fuel Cost Recovery" in Item 8 of the Form 10-K for additional information.

Market-Based Rate Authority

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters – Market-Based Rate Authority" of Mississippi Power in Item 7 of the Form 10-K for additional information regarding the traditional electric operating companies' and Southern Power's market power proceeding and amendment to their market-rate tariff.

On May 17, 2017, the FERC accepted the traditional electric operating companies' (including Mississippi Power's) and Southern Power's compliance filing accepting the terms of the FERC's February 2, 2017 order regarding an amendment by the traditional electric operating companies (including Mississippi Power) and Southern Power to their market-based rate tariff. While the FERC's order references the traditional electric operating companies' (including Mississippi Power's) and Southern Power's market power proceeding, it remains a separate, ongoing matter.

Retail Regulatory Matters

Mississippi Power's rates and charges for service to retail customers are subject to the regulatory oversight of the Mississippi PSC. Mississippi Power's rates are a combination of base rates and several separate cost recovery

clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased power, energy efficiency programs, ad valorem taxes, property damage, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through Mississippi Power's base rates. See Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters" and "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under " Regulatory Matters – Mississippi Power " and " Integrated Coal Gasification Combined Cycle " herein for additional information.

Renewables

Mississippi Power placed in service two solar projects in January 2017 and June 2017. A third solar project is expected to be placed in service in the third quarter 2017. Mississippi Power may retire the renewable energy credits (REC) generated on behalf of its customers or sell the RECs, separately or bundled with energy, to third parties.

On June 9, 2017, Mississippi Power submitted a CPCN to the Mississippi PSC for the approval of construction, operation, and maintenance of a 52.5-MW solar energy generating facility, which, if approved, is expected to be placed in service by January 2020. The ultimate outcome of this matter cannot be determined at this time.

Performance Evaluation Plan

On March 15, 2017, Mississippi Power submitted its annual PEP lookback filing for 2016, which reflected the need for a $5 million surcharge to be recovered from customers. The filing has been suspended for review by the Mississippi PSC. The ultimate outcome of this matter cannot be determined at this time.

Energy Efficiency

On July 6, 2017, the Mississippi PSC issued an order approving Mississippi Power's Energy Efficiency Cost Rider compliance filing, which increased annual retail revenues by approximately $2 million effective with the first billing cycle for August 2017.

Environmental Compliance Overview Plan

On May 4, 2017, the Mississippi PSC approved Mississippi Power's ECO Plan filing for 2017, which requested the maximum 2% annual increase in revenues, approximately $18 million, primarily related to the Plant Daniel Units 1 and 2 scrubbers placed in service in 2015. The rates became effective with the first billing cycle for June 2017. Approximately $26 million of related revenue requirements in excess of the 2% maximum was deferred for inclusion in the 2018 filing.

Fuel Cost Recovery

At June 30, 2017 , the amount of over-recovered retail fuel costs included on the condensed balance sheet was $14 million compared to $37 million at December 31, 2016.

Ad Valorem Tax Adjustment

On July 6, 2017, the Mississippi PSC approved Mississippi Power's annual ad valorem tax adjustment factor filing for 2017, which included an annual rate increase of 0.85%, or $8 million in annual retail revenues, primarily due to increased assessments.

Integrated Coal Gasification Combined Cycle

See Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K for information regarding Mississippi Power's construction of the Kemper IGCC.

Kemper IGCC Overview

The Kemper IGCC was designed to utilize IGCC technology with an expected output capacity of 582 MWs and to be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by Mississippi Power

and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation in 2013. In connection with the Kemper IGCC, Mississippi Power constructed approximately 61 miles of CO_2 pipeline infrastructure for the transport of captured CO_2 for use in enhanced oil recovery.

Kemper IGCC Schedule and Cost Estimate

In 2012, the Mississippi PSC issued the 2012 MPSC CPCN Order, a detailed order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC. The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC CPCN Order was $2.4 billion , net of $245 million of Initial DOE Grants and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and AFUDC related to the Kemper IGCC. The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion , with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. The Kemper IGCC was originally projected to be placed in service in May 2014. Mississippi Power placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service in August 2014. The remainder of the plant includes the gasifiers and the gas clean-up facilities. The initial production of syngas began on July 14, 2016 for gasifier "B" and on September 13, 2016 for gasifier "A." Mississippi Power achieved integrated operation of both gasifiers on January 29, 2017, including the production of electricity from syngas in both combustion turbines. During testing, the plant produced and captured CO_2 , and produced sulfuric acid and ammonia, each of acceptable quality under the related off-take agreements. However, Mississippi Power experienced numerous challenges during the extended start-up process to achieve integrated operation of the gasifiers on a sustained basis. Most recently, in May 2017, after achieving these milestones, Mississippi Power determined that a critical system component, the syngas coolers, would need replacement sooner than originally planned, which would require significant lead time and significant cost. In addition, the long-term natural gas price forecast has decreased significantly and the estimated cost of operating and maintaining the facility during the first five full years of operations increased significantly since certification.

On June 21, 2017, the Mississippi PSC stated its intent to issue an order (which occurred on July 6, 2017) directing Mississippi Power to pursue a settlement under which the Kemper County energy facility would be operated as a natural gas plant, rather than an IGCC plant, and address all issues associated with the Kemper IGCC. On June 28, 2017, Mississippi Power notified the Mississippi PSC that it would begin a process to suspend operations and start-up activities on the gasifier portion of the Kemper IGCC, given the uncertainty as to the future of the gasifier portion of the Kemper IGCC. Mississippi Power expects to continue to operate the combined cycle portion of the Kemper IGCC as it has done since August 2014.

MISSISSIPPI POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Mississippi Power's Kemper IGCC 2010 project estimate, cost estimate at the time of project suspension (which includes the impacts of the Mississippi Supreme Court's (Court) decision discussed herein under " Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order "), and actual costs incurred as of June 30, 2017 , all of which include 100% of the costs for the Kemper IGCC, are as follows:

Cost Category	2010 Project Estimate [a]	Cost Estimate at Suspension [b]	**June 30, 2017 Actual Costs**
		(in billions)	
Plant Subject to Cost Cap [c][e]	$ 2.40	$ 5.95	**$ 5.68**
Lignite Mine and Equipment	0.21	0.23	**0.23**
CO_2 Pipeline Facilities	0.14	0.11	**0.11**
AFUDC [d]	0.17	0.85	**0.85**
Combined Cycle and Related Assets Placed in Service – Incremental [e]	—	0.05	**0.05**
General Exceptions	0.05	0.10	**0.08**
Deferred Costs [e]	—	0.23	**0.23**
Additional DOE Grants	—	(0.14)	**(0.14)**
Total Kemper IGCC	$ 2.97	$ 7.38	**$ 7.09**

(a) Represents the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities approved in 2011 by the Mississippi PSC, as well as the lignite mine and equipment, AFUDC, and general exceptions.

(b) Represents actual costs through June 30, 2017 and projected costs at the time of project suspension, including estimated post-in-service costs which were expected to be subject to the cost cap.

(c) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion , net of the Initial DOE Grants and excluding the Cost Cap Exceptions. The Cost Estimate at Suspension and the Actual Costs include non-incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service in August 2014 that are subject to the $2.88 billion cost cap and exclude post-in-service costs for the lignite mine. See " Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order " herein for additional information.

(d) Mississippi Power's 2010 Project Estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC as described in " Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order ." The Cost Estimate at Suspension also reflects the impact of a settlement agreement with the wholesale customers for cost-based rates under FERC's jurisdiction. See " FERC Matters " herein for additional information.

(e) Non-capital Kemper IGCC-related costs incurred during construction were initially deferred as regulatory assets. Some of these costs are included in current rates and are being recognized through income; however, such costs remained in the Cost Estimate at Suspension and are reflected in the Actual Costs at June 30, 2017 . The equity return associated with assets placed in service and other non-CWIP accounts deferred for regulatory purposes, as well as the wholesale portion of debt carrying costs, whether deferred or recognized through income, was not included in the Cost Estimate at Suspension or in the Actual Costs at June 30, 2017 . At June 30, 2017, such deferred amounts totaled $33 million and $1 million , respectively.

Mississippi Power recorded pre-tax charges to income for revisions to the cost estimate of $196 million ($121 million after tax) in the second quarter through May 31, 2017 and a total of $305 million ($188 million after tax) for year-to-date through May 31, 2017. In the aggregate, Mississippi Power incurred charges of $3.07 billion ($1.89 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through May 31, 2017. The May 31, 2017 cost estimate included approximately $175 million of estimated costs to be incurred beyond the then-estimated in-service date of June 30, 2017 that were expected to be subject to the $2.88 billion cost cap.

While the ultimate disposition of the gasification portions of the Kemper IGCC remains subject to the Mississippi PSC's jurisdiction, including the potential resolution of the matters addressed in the Kemper Settlement Order, given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility, cost recovery of the gasification portions is no longer probable; therefore, Mississippi Power recorded an additional charge to income in June 2017 of $2.8 billion ($2.0 billion after tax), which includes estimated costs associated with the gasification portions of the plant and lignite mine. In the event the gasification portions of the project are

ultimately canceled, additional pre-tax costs currently estimated at approximately $100 million to $200 million are expected to be incurred.

In the aggregate, Mississippi Power recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC totaling $3.0 billion for the second quarter 2017 and $3.1 billion for the six months ended June 30, 2017.

As of June 30, 2017, Mississippi Power has recorded a total of approximately $1.3 billion in costs associated with the combined cycle portion of the Kemper IGCC, of which $1.2 billion is included in plant in service, $14 million in materials and supplies, $22 million in other regulatory assets, current, and $95 million in other regulatory assets, deferred.

Rate Recovery of Kemper IGCC Costs

Given the variety of potential scenarios and the uncertainty of the outcome of future regulatory proceedings with the Mississippi PSC (and any subsequent related legal challenges), the ultimate outcome of the rate recovery matters discussed herein, including the resolution of legal challenges, cannot now be determined but could result in further material charges that could have a material impact on Mississippi Power's results of operations, financial condition, and liquidity.

Kemper IGCC Settlement Docket

On June 21, 2017, the Mississippi PSC stated its intent to issue an order (which occurred on July 6, 2017) directing Mississippi Power to pursue a settlement under which the Kemper County energy facility would be operated as a natural gas plant, rather than an IGCC plant, and address all issues associated with the Kemper IGCC. The Kemper Settlement Order established the Kemper IGCC Settlement Docket. The Mississippi PSC requested any such proposed settlement agreement reflect: (i) at a minimum, no rate increase to Mississippi Power customers (with a rate reduction focused on residential customers encouraged); (ii) removal of all cost risk to customers associated with the Kemper IGCC gasifier and related assets; and (iii) modification or amendment of the CPCN for the Kemper IGCC to allow only for ownership and operation of a natural gas facility. The Kemper Settlement Order provides that any related settlement agreement be filed within 45 days from the effective date of the Kemper Settlement Order. If a settlement agreement is filed, a hearing will be set 45 days from the date of the settlement's filing, and the appropriate scheduling order will be established.

Although the ability to achieve a negotiated settlement is uncertain, Mississippi Power intends to pursue any available settlement alternatives. In addition, the Kemper Settlement Order provides that, in the event a settlement agreement is not reached, the Mississippi PSC reserves its right to take any appropriate steps, including issuing an order to show cause as to why the CPCN for the Kemper IGCC should not be revoked.

On June 28, 2017, Mississippi Power notified the Mississippi PSC that it would begin a process to suspend operations and start-up activities on the gasifier portion of the Kemper IGCC, given the uncertainty as to the future of the gasifier portion of the Kemper IGCC. Mississippi Power expects to continue to operate the combined cycle portion of the Kemper IGCC as it has done since August 2014.

At June 30, 2017, approximately $3.3 billion in actual Kemper IGCC costs were not reflected in Mississippi Power's retail and wholesale rates, of which $0.5 billion was related to the combined cycle and associated facilities and $2.8 billion was related to the gasification portions of the Kemper IGCC.

While the ultimate disposition of the gasification portions of the Kemper IGCC remains subject to the Mississippi PSC's jurisdiction, including the potential resolution of the matters addressed in the Kemper Settlement Order, given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility, cost recovery of the gasification portions is no longer probable; therefore, Mississippi Power recorded an additional charge to income in June 2017 of $2.8 billion ($2.0 billion after tax), which includes estimated costs associated with the gasification portions of the plant and lignite mine. In the event the gasification portions of the project are ultimately canceled, additional pre-tax costs currently estimated at approximately $100 million to $200 million are expected to be incurred.

As of June 30, 2017, Mississippi Power has recorded a total of approximately $1.3 billion in costs associated with the combined cycle portion of the Kemper IGCC including transmission and related regulatory assets, of which $0.8 billion is included in retail and wholesale rates. The $0.5 billion not included in current rates includes costs in excess of the original 2010 estimate for the combined cycle portion of the facility, as well as the 15% that was previously contracted to SMEPA. Mississippi Power has calculated the revenue requirements resulting from these remaining costs, using reasonable assumptions for amortization periods, and expects them to be recovered through rates consistent with the Mississippi PSC's requested settlement conditions. The ultimate outcome will be determined by the Mississippi PSC in the Kemper IGCC Settlement Docket proceedings.

Prudence

On August 17, 2016, the Mississippi PSC issued an order establishing a discovery docket to manage all filings related to the prudence of the Kemper IGCC. On October 3, 2016, Mississippi Power made a required compliance filing, which included a review and explanation of differences between the Kemper IGCC project estimate set forth in the 2010 CPCN proceedings and the most recent Kemper IGCC project estimate, as well as comparisons of current cost estimates and current expected plant operational parameters to the estimates presented in the 2010 CPCN proceedings for the first five years after the Kemper IGCC is placed in service. Compared to amounts presented in the 2010 CPCN proceedings, operations and maintenance expenses have increased an average of $105 million annually and maintenance capital has increased an average of $44 million annually for the first full five years of operations for the Kemper IGCC. Additionally, while the current estimated operational availability estimates reflect ultimate results similar to those presented in the 2010 CPCN proceedings, the ramp up period for the current estimates reflects a lower starting point and a slower escalation rate. On November 17, 2016, Mississippi Power submitted a supplemental filing to the October 3, 2016 compliance filing to present revised non-fuel operations and maintenance expense projections for the first year after the Kemper IGCC is placed in service. This supplemental filing included approximately $68 million in additional estimated operations and maintenance costs expected to be required to support the operations of the Kemper IGCC during that period.

Mississippi Power responded to numerous requests for information from interested parties in the discovery docket, which is now complete. Mississippi Power expects the Mississippi PSC to utilize this information in connection with the ultimate resolution of Kemper IGCC cost recovery.

Economic Viability Analysis

In the fourth quarter 2016, as a part of its Integrated Resource Plan process, the Southern Company system completed its regular annual updated fuel forecast, the 2017 Annual Fuel Forecast. This updated fuel forecast reflected significantly lower long-term estimated costs for natural gas than were previously projected. As a result of the updated long-term natural gas forecast, as well as the revised operating expense projections reflected in the discovery docket filings discussed above, on February 21, 2017, Mississippi Power filed an updated project economic viability analysis of the Kemper IGCC as required under the 2012 MPSC CPCN Order confirming authorization of the Kemper IGCC. The project economic viability analysis measures the life cycle economics of the Kemper IGCC compared to feasible alternatives, natural gas combined cycle generating units, under a variety of scenarios and considering fuel, operating and capital costs, and operating characteristics, as well as federal and state taxes and incentives. The reduction in the projected long-term natural gas prices in the 2017 Annual Fuel Forecast and, to a lesser extent, the increase in the estimated Kemper IGCC operating costs, negatively impact the updated project economic viability analysis.

Mississippi Power expects the Mississippi PSC to address this matter in connection with the Kemper IGCC Settlement Docket.

2015 Rate Case

On August 13, 2015, the Mississippi PSC approved Mississippi Power's request for interim rates, which presented an alternative rate proposal (In-Service Asset Proposal) designed to recover Mississippi Power's costs associated with the Kemper IGCC assets that are commercially operational and currently providing service to customers (the

transmission facilities, combined cycle, natural gas pipeline, and water pipeline) and other related costs. The interim rates were designed to collect approximately $159 million annually and became effective in September 2015, subject to refund and certain other conditions.

On December 3, 2015, the Mississippi PSC issued the In-Service Asset Rate Order adopting in full the 2015 Stipulation entered into between Mississippi Power and the MPUS regarding the In-Service Asset Proposal. The In-Service Asset Rate Order provided for retail rate recovery of an annual revenue requirement of approximately $126 million , based on Mississippi Power's actual average capital structure, with a maximum common equity percentage of 49.733% , a 9.225% return on common equity, and actual embedded interest costs. The In-Service Asset Rate Order also included a prudence finding of all costs in the stipulated revenue requirement calculation for the in-service assets. The stipulated revenue requirement excluded the costs of the Kemper IGCC related to the 15% undivided interest that was previously projected to be purchased by SMEPA but reserved Mississippi Power's right to seek recovery in a future proceeding. See " Termination of Proposed Sale of Undivided Interest " herein for additional information. With implementation of the new rates on December 17, 2015, the interim rates were terminated and, in March 2016, Mississippi Power completed customer refunds of approximately $11 million for the difference between the interim rates collected and the permanent rates.

In 2011, the Mississippi PSC authorized Mississippi Power to defer all non-capital Kemper IGCC-related costs to a regulatory asset through the in-service date. In connection with the implementation of the In-Service Asset Order and wholesale rates, Mississippi Power began expensing certain ongoing project costs and certain retail debt carrying costs that previously were deferred and began amortizing certain regulatory assets associated with assets placed in service and consulting and legal fees. The amortization periods for these regulatory assets vary from two years to 10 years as set forth in the In-Service Asset Rate Order and the settlement agreement with wholesale customers. As of June 30, 2017, the balance associated with these regulatory assets was $117 million, of which $22 million is included in current assets. See "FERC Matters" herein for additional information related to the 2016 settlement agreement with wholesale customers.

The In-Service Asset Rate Order requires Mississippi Power to submit an annual true-up calculation of its actual cost of capital, compared to the stipulated total cost of capital, with the first occurring as of May 31, 2016. At June 30, 2017, Mississippi Power's related regulatory liability included in its balance sheet totaled approximately $10 million.

As required by the In-Service Asset Rate Order, on June 5, 2017, Mississippi Power made a rate filing requesting to adjust the amortization schedules of the regulatory assets reviewed and determined prudent in the In-Service Asset Order in a manner that would not change customer rates or annual revenues. On June 28, 2017, the Mississippi PSC suspended this filing. On July 6, 2017, the Mississippi PSC issued an order requiring Mississippi Power to establish a regulatory liability account to maintain current rates related to the Kemper IGCC following the July 2017 completion of the amortization period for certain regulatory assets approved in the In-Service Asset Rate Order that would allow for subsequent refund if the Mississippi PSC deems the rates unjust and unreasonable.

2013 MPSC Rate Order

In January 2013, Mississippi Power entered into a settlement agreement with the Mississippi PSC that was intended to establish the process for resolving matters regarding cost recovery related to the Kemper IGCC (2013 Settlement Agreement). Under the 2013 Settlement Agreement, Mississippi Power agreed to limit the portion of prudently-incurred Kemper IGCC costs to be included in retail rate base to the $2.4 billion certificated cost estimate, plus the Cost Cap Exceptions, but excluding AFUDC, and any other costs permitted or determined to be excluded from the $2.88 billion cost cap by the Mississippi PSC. In March 2013, the Mississippi PSC issued a rate order approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014 (2013 MPSC Rate Order) to be used to mitigate customer rate impacts after the Kemper IGCC was placed in service, based on a mirror CWIP methodology (Mirror CWIP rate).

On February 12, 2015, the Court reversed the 2013 MPSC Rate Order and, on July 7, 2015, the Mississippi PSC ordered that the Mirror CWIP rate be terminated effective July 20, 2015 and required the fourth quarter 2015 refund of the $342 million previously collected, along with associated carrying costs of $29 million .

Because the 2013 MPSC Rate Order did not provide for the inclusion of CWIP in rate base as permitted by the Baseload Act, Mississippi Power continued to record AFUDC on the Kemper IGCC. Between the original May 2014 estimated in-service date and the June 2017 project suspension date, Mississippi Power recorded $493 million of AFUDC on the Kemper IGCC subject to the $2.88 billion cost cap and Cost Cap Exception amounts, of which $459 million related to the gasification portions of the Kemper IGCC.

Mississippi Power expects the Mississippi PSC to address this matter in connection with the Kemper IGCC Settlement Docket.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, Mississippi Power owns the lignite mine and equipment and mineral reserves located around the Kemper IGCC site. The mine started commercial operation in June 2013.

In 2010, Mississippi Power executed a 40 -year management fee contract with Liberty Fuels Company, LLC (Liberty Fuels), a wholly-owned subsidiary of The North American Coal Corporation, which developed, constructed, and is responsible for the mining operations through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and Mississippi Power has a contractual obligation to fund all reclamation activities. In addition to the obligation to fund the reclamation activities, Mississippi Power provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses. See Note 1 to the financial statements of Mississippi Power under "Asset Retirement Obligations and Other Costs of Removal" and "Variable Interest Entities" in Item 8 of the Form 10-K for additional information.

In addition, Mississippi Power constructed the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. Mississippi Power entered into agreements with Denbury Onshore (Denbury) and Treetop Midstream Services, LLC (Treetop), pursuant to which Denbury would purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop would purchase 30% of the CO_2 captured from the Kemper IGCC. On June 3, 2016, Mississippi Power cancelled its contract with Treetop and amended its contract with Denbury to reflect, among other things, Denbury's agreement to purchase 100% of the CO_2 captured from the Kemper IGCC and an initial contract term of 16 years. Denbury has the right to terminate the contract at any time because Mississippi Power did not place the Kemper IGCC in service by July 1, 2017.

The ultimate outcome of these matters cannot be determined at this time.

Termination of Proposed Sale of Undivided Interest

In 2010 and as amended in 2012, Mississippi Power and SMEPA entered into an agreement whereby SMEPA agreed to purchase a 15% undivided interest in the Kemper IGCC (15% Undivided Interest). On May 20, 2015, SMEPA notified Mississippi Power of its termination of the agreement. Mississippi Power previously received a total of $275 million of deposits from SMEPA that were required to be returned to SMEPA with interest. On June 3, 2015, Southern Company, pursuant to its guarantee obligation, returned approximately $301 million to SMEPA. Subsequently, Mississippi Power issued a promissory note in the aggregate principal amount of approximately $301 million to Southern Company, which was repaid in June 2017.

Litigation

On April 26, 2016, a complaint against Mississippi Power was filed in Harrison County Circuit Court (Circuit Court) by Biloxi Freezing & Processing Inc., Gulfside Casino Partnership, and John Carlton Dean, which was amended and refiled on July 11, 2016 to include, among other things, Southern Company as a defendant. The individual plaintiff alleges that Mississippi Power and Southern Company violated the Mississippi Unfair Trade Practices Act. All plaintiffs have alleged that Mississippi Power and Southern Company concealed, falsely

represented, and failed to fully disclose important facts concerning the cost and schedule of the Kemper IGCC and that these alleged breaches have unjustly enriched Mississippi Power and Southern Company. The plaintiffs seek unspecified actual damages and punitive damages; ask the Circuit Court to appoint a receiver to oversee, operate, manage, and otherwise control all affairs relating to the Kemper IGCC; ask the Circuit Court to revoke any licenses or certificates authorizing Mississippi Power or Southern Company to engage in any business related to the Kemper IGCC in Mississippi; and seek attorney's fees, costs, and interest. The plaintiffs also seek an injunction to prevent any Kemper IGCC costs from being charged to customers through electric rates. On June 23, 2017, the Circuit Court ruled in favor of motions by Southern Company and Mississippi Power and dismissed the case. On July 7, 2017, the plaintiffs filed notice to appeal to the Court.

On June 9, 2016, Treetop, Greenleaf CO_2 Solutions, LLC (Greenleaf), Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group filed a complaint against Mississippi Power, Southern Company, and SCS in the state court in Gwinnett County, Georgia. The complaint relates to the cancelled CO_2 contract with Treetop and alleges fraudulent misrepresentation, fraudulent concealment, civil conspiracy, and breach of contract on the part of Mississippi Power, Southern Company, and SCS and seeks compensatory damages of $100 million , as well as unspecified punitive damages. Southern Company, Mississippi Power, and SCS have moved to compel arbitration pursuant to the terms of the CO_2 contract, which the court granted on May 4, 2017. On June 28, 2017, Treetop, Greenleaf, Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group filed a claim for arbitration requesting $500 million in damages.

Mississippi Power believes these legal challenges have no merit; however, an adverse outcome in these proceedings could have a material impact on Mississippi Power's results of operations, financial condition, and liquidity. Mississippi Power will vigorously defend itself in these matters, and the ultimate outcome of these matters cannot be determined at this time.

Baseload Act

In 2008, the Baseload Act was signed by the Governor of Mississippi. The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently-incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant.

Income Tax Matters

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Income Tax Matters" of Mississippi Power in Item 7 of the Form 10-K and Note (G) to the Condensed Financial Statements under " Section 174 Research and Experimental Deduction " herein for additional information on bonus depreciation, investment tax credits, and the Section 174 research and experimental deduction.

Bonus Depreciation

Approximately $370 million of positive cash flows is expected to result from bonus depreciation for the 2017 tax year, but may not all be realized in 2017 due to net operating loss projections for the 2017 tax year, and is dependent upon placing the remainder of the Kemper IGCC in service by December 31, 2017. If the suspension of the Kemper IGCC start-up activities results in an abandonment, any amount previously estimated as bonus depreciation would be claimed as a deduction under IRC Section 165. As of June 30, 2017, $82 million has been received through quarterly income tax refunds for bonus depreciation related to the Kemper IGCC, which may be subject to repayment. See Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined

Cycle" herein and Note (G) to the Condensed Financial Statements herein for additional information. The ultimate outcome of this matter cannot be determined at this time.

Section 174 Research and Experimental Deduction

Southern Company, on behalf of Mississippi Power, has reflected deductions for research and experimental (R&E) expenditures related to the Kemper IGCC in its federal income tax calculations since 2013 and filed amended federal income tax returns for 2008 through 2013 to also include such deductions. In December 2016, Southern Company and the IRS reached a proposed settlement, subject to approval of the U.S. Congress Joint Committee on Taxation, resolving a methodology for these deductions. Due to the uncertainty related to this tax position, Mississippi Power had unrecognized tax benefits associated with these R&E deductions totaling approximately $464 million as of June 30, 2017. If the suspension of the Kemper IGCC start-up activities results in an abandonment, any amount not allowed under IRC Section 174 would be claimed as a deduction under IRC Section 165, and would result in a reversal of the related unrecognized tax benefits, excluding interest. See Notes (B) and (G) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" and "Section 174 Research and Experimental Deduction," respectively, herein for additional information. This matter is expected to be resolved in the next 12 months; however, the ultimate outcome of this matter cannot be determined at this time.

Other Matters

Mississippi Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Mississippi Power is subject to certain claims and legal actions arising in the ordinary course of business. Mississippi Power's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions , CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation against Mississippi Power cannot be predicted at this time; however, for current proceedings not specifically reported in Note (B) to the Condensed Financial Statements herein , management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Mississippi Power's financial statements. See Note (B) to the Condensed Financial Statements herein for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

The SEC is conducting a formal investigation of Southern Company and Mississippi Power concerning the estimated costs and expected in-service date of the Kemper IGCC. Southern Company and Mississippi Power believe the investigation is focused primarily on periods subsequent to 2010 and on accounting matters, disclosure controls and procedures, and internal controls over financial reporting associated with the Kemper IGCC. See ACCOUNTING POLICIES – " Application of Critical Accounting Policies and Estimates " herein for additional information on the Kemper IGCC. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to have a material impact on the financial statements of Mississippi Power.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Mississippi Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Mississippi Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Mississippi Power'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. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of

Mississippi Power in Item 7 of the Form 10-K for a complete discussion of Mississippi Power's critical accounting policies and estimates related to Utility Regulation, Asset Retirement Obligations, Pension and Other Postretirement Benefits, AFUDC, Unbilled Revenues, and Contingent Obligations.

Kemper IGCC Rate Recovery

For periods prior to the second quarter 2017, significant accounting estimates included Kemper IGCC estimated construction costs, project completion date, and rate recovery. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Kemper IGCC Estimated Construction Costs, Project Completion Date, and Rate Recovery" of Mississippi Power in Item 7 of the Form 10-K for additional information. Mississippi Power recorded total pre-tax charges to income related to the Kemper IGCC of $428 million ($264 million after tax) in 2016, $365 million ($226 million after tax) in 2015, $868 million ($536 million after tax) in 2014, and $1.2 billion ($729 million after tax) in prior years.

As a result of the Mississippi PSC's June 21, 2017 stated intent to issue an order (which occurred on July 6, 2017) directing Mississippi Power to pursue a settlement under which the Kemper County energy facility would be operated as a natural gas plant rather than an IGCC plant, as well as Mississippi Power's June 28, 2017 suspension of the operation and start-up of the gasifier portion of the Kemper IGCC, the estimated construction costs and project completion date are no longer considered significant accounting estimates. Significant accounting estimates for the June 30, 2017 financial statements presented herein include the overall assessment of rate recovery for the Kemper County energy facility and the estimated costs for the potential cancellation of the Kemper IGCC.

While the ultimate disposition of the gasification portions of the Kemper IGCC remains subject to the Mississippi PSC's jurisdiction, including the potential resolution of the matters addressed in the Kemper Settlement Order, given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility, cost recovery of the gasification portions is no longer probable; therefore, Mississippi Power recorded an additional charge to income in June 2017 of $2.8 billion ($2.0 billion after tax), which includes estimated costs associated with the gasification portions of the plant and lignite mine. In the event the gasification portions of the project are ultimately canceled, additional pre-tax costs currently estimated at approximately $100 million to $200 million are expected to be incurred.

As of June 30, 2017, Mississippi Power has recorded a total of approximately $1.3 billion in costs associated with the combined cycle portion of the Kemper IGCC including transmission and related regulatory assets, of which $0.8 billion is included in retail and wholesale rates. The $0.5 billion not included in current rates includes costs in excess of the original 2010 estimate for the combined cycle portion of the facility, as well as the 15% that was previously contracted to SMEPA. Mississippi Power has calculated the revenue requirements resulting from these remaining costs, using reasonable assumptions for amortization periods, and expects them to be recovered through rates consistent with the Mississippi PSC's requested settlement conditions. The ultimate outcome will be determined by the Mississippi PSC in the Kemper IGCC Settlement Docket proceedings.

In the aggregate, since the Kemper IGCC project started, Mississippi Power has incurred charges of $5.96 billion ($3.94 billion after tax) through June 30, 2017. Mississippi Power recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC of $3.0 billion ($2.1 billion after tax) and $81 million ($50 million after tax) in the second quarter 2017 and the second quarter 2016, respectively, and total pre-tax charges of $3.1 billion ($2.2 billion after tax) and $134 million ($83 million after tax) year-to-date in 2017 and 2016, respectively.

Given the significant judgment involved in estimating the costs to cancel the gasifier portion of the Kemper IGCC, the ultimate rate recovery for the Kemper IGCC, including the $0.5 billion of combined cycle-related costs not yet in rates, and the impact on Mississippi Power's results of operations, Mississippi Power considers these items to be critical accounting estimates. See Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information.

Recently Issued Accounting Standards

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 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.

While Mississippi Power expect s most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of all revenue arrangements. The majority of Mississippi Power'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 . Mississippi Power expect s that the revenue from contracts with these customers will not result in a significant shift in the timing of revenue recognition for such sales .

Mississippi Power's ongoing evaluation of other revenue streams and related contracts includes unregulated sales to customers. Some revenue arrangements, such as alternative revenue programs, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed or presented separately from revenues under ASC 606 on Mississippi Power's financial statements, if material. In addition, the power and utilities industry continues to evaluate other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). Although final implementation guidance has not been issued, Mississippi Power expect s CIAC to be out of the scope of ASC 606.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. Mississippi Power intend s to use the modified retrospective method of adoption effective January 1, 2018. Mississippi Power has also elected to utilize practical expedients which allow 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, disclosures will include comparative information on 2018 financial statement line items under current guidance. While the adoption of ASC 606, including the cumulative-effect adjustment, is not expected to have a material impact on either the timing or amount of revenues recognized in Mississippi Power's financial statements, Mississippi Power will continue to evaluate the requirements, as well as any additional clarifying guidance that may be issued.

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 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 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 annual periods beginning after December 15, 2017, including interim periods within those annual periods. Mississippi Power is currently evaluating the new standard. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in Mississippi Power'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 adoption of ASU 2017-07 is not expected to have a material impact on Mississippi Power's financial statements.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Overview" of Mississippi Power in Item 7 of the Form 10-K and FUTURE EARNINGS POTENTIAL – " Integrated Coal Gasification Combined Cycle " herein for additional information. Earnings for the six months ended June 30, 2017 were negatively affected by revisions to the cost estimate for the Kemper IGCC.

Mississippi Power's capital expenditures and debt maturities are expected to materially exceed operating cash flows through 2022. Projected capital expenditures in that period include investments to maintain existing generation facilities, to add environmental modifications to existing generating units, and to expand and improve transmission and distribution facilities.

In the second quarter 2017, Mississippi Power borrowed an additional $40 million under a promissory note issued to Southern Company. In June 2017, Southern Company made equity contributions totaling $1.0 billion to Mississippi Power. Mississippi Power used a portion of the proceeds to prepay $901 million of outstanding debt.

As of June 30, 2017, Mississippi Power's current liabilities exceeded current assets by approximately $930 million primarily due to $935 million in long-term debt that matures within the next 12 months and $107 million of short-term debt. Mississippi Power intends to utilize operating cash flows, lines of credit, and bank term loans, as market conditions permit, as well as, under certain circumstances, commercial paper and/or equity contributions and/or loans from Southern Company to fund Mississippi Power's short-term capital needs.

Net cash provided from operating activities totaled $135 million for the first six months of 2017, a decrease of $2 million as compared to the corresponding period in 2016. The decrease in cash provided from operating activities is primarily due to lower taxes related to the Kemper IGCC, the timing of payments for ad valorem taxes and materials and supplies, and the timing of payments received from affiliates and customers, partially offset by the completion of Mirror CWIP refunds in 2016. See Notes (B) and (G) to the Condensed Financial Statements under " Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs " and " Unrecognized Tax Benefits – Section 174 Research and Experimental Deduction " herein for additional information. Net cash used for investing activities totaled $361 million for the first six months of 2017 primarily due to gross property additions related to the Kemper IGCC. Net cash provided from financing activities totaled $142 million for the first six months of 2017 primarily due to capital contributions from Southern Company, offset by redemptions of long-term debt. Cash flows from financing activities vary from period to period based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for the first six months of 2017 include an increase in paid-in capital of $1.0 billion due to capital contributions from Southern Company, a portion of which was used to repay $300 million of securities due within one year, $591 million of long-term debt, and $10 million of short-term debt. Long-term debt decreased primarily due to the reclassification of $1.2 billion in unsecured term loans to securities due within one year. Other significant changes include decreases of $2.5 billion in construction work in progress, $1.1 billion in total common stockholder's equity, $352 million in accumulated deferred income taxes, and $300 million in deferred charges related to income taxes. All of these changes primarily result from the Kemper IGCC estimated loss. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Mississippi Power in Item 7 of the Form 10-K for a description of Mississippi Power's capital requirements for its construction program, including estimated capital expenditures for new generating resources and to comply with existing environmental statutes and regulations, scheduled maturities of long-term debt, as well as related interest, leases, purchase commitments, derivative

obligations, preferred stock dividends, trust funding requirements, and unrecognized tax benefits. Approximately $935 million will be required through June 30, 2018 to fund maturities of long-term debt and $17 million will be required to fund maturities of short-term debt. In addition, Mississippi Power has $40 million of tax-exempt variable rate demand obligations that are supported by short-term credit facilities and $50 million of fixed rate pollution control revenue bonds that are required to be remarketed over the next 12 months. See " Sources of Capital " and FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" herein for additional information.

The construction program of Mississippi Power is currently estimated to be $561 million for 2017 , $192 million for 2018, $182 million for 2019, $235 million for 2020, $199 million for 2021, and $245 million for 2022. These estimated expenditures do not include potential compliance costs that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from existing, new, modified, or reconstructed fossil-fuel-fired electric generating units.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in FERC rules and regulations; Mississippi PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital.

Sources of Capital

Mississippi Power plans to obtain the funds required for construction and other purposes from operating cash flows, external security issuances, term loans, and/or short-term debt, as well as, under certain circumstances, equity contributions and/or loans from Southern Company. The amount, type, and timing of future financings will depend upon regulatory approval, prevailing market conditions, and other factors, which includes resolution of the Kemper County energy facility cost recovery. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" and – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" of Mississippi Power in Item 7 of the Form 10-K for additional information.

On February 28, 2017, the maturity dates for $551 million in promissory notes to Southern Company were extended to July 31, 2018. In the second quarter 2017, Mississippi Power borrowed an additional $40 million under a promissory note issued to Southern Company. In June 2017, Southern Company made equity contributions totaling $1.0 billion to Mississippi Power. Mississippi Power used a portion of the proceeds to (i) prepay $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan; (ii) repay all of the $591 million outstanding principal amount of promissory notes to Southern Company; and (iii) repay $10 million of the outstanding principal amount of bank loans.

As of June 30, 2017, Mississippi Power's current liabilities exceeded current assets by approximately $930 million primarily due to $935 million in long-term debt that matures within the next 12 months and $107 million of short-term debt. Mississippi Power intends to utilize operating cash flows, lines of credit, and bank term loans, as market conditions permit, as well as, under certain circumstances, commercial paper and/or equity contributions and/or loans from Southern Company to fund Mississippi Power's short-term capital needs. Specifically, Mississippi Power has been informed by Southern Company that in the event sufficient funds are not available from external sources, Southern Company intends to provide Mississippi Power with loans and/or equity contributions sufficient to fund the remaining indebtedness scheduled to mature and other cash needs over the next 12 months. Therefore, Mississippi Power's financial statement presentation contemplates continuation of Mississippi Power as a going concern as a result of Southern Company's anticipated ongoing financial support of Mississippi Power. For additional information, see Notes 1 and 6 to the financial statements of Mississippi Power under "Recently Issued

Accounting Standards" and "Going Concern," respectively, in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Going Concern" herein.

At June 30, 2017 , Mississippi Power had approximately $140 million of cash and cash equivalents. Committed credit arrangements with banks at June 30, 2017 were as follows:

Expires			Executable Term Loans		Expires Within One Year	
2017	Total	Unused	One Year	Two Years	Term Out	No Term Out
			(in millions)			
$ 113	$ 113	$ 100	$ —	$ 13	$ 13	$ 100

See Note 6 to the financial statements of Mississippi Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under " Bank Credit Arrangements " herein for additional information.

Most of these bank credit arrangements, as well as Mississippi Power's term loan agreement, contain covenants that limit debt levels and typically contain cross acceleration to other indebtedness (including guarantee obligations) of Mississippi Power. Such cross-acceleration provisions to other indebtedness would trigger an event of default if Mississippi Power defaulted on indebtedness, the payment of which was then accelerated. At June 30, 2017 , Mississippi Power was in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowing.

Subject to applicable market conditions, Mississippi Power expects to seek to renew or replace its credit arrangements as needed, prior to expiration. In connection therewith, Mississippi Power may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

A portion of the $100 million unused credit arrangements with banks is allocated to provide liquidity support to Mississippi Power's pollution control revenue bonds. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of June 30, 2017 was approximately $40 million . In addition, at June 30, 2017 , Mississippi Power had approximately $50 million of fixed rate pollution control bonds outstanding that were required to be remarketed within the next 12 months.

Short-term borrowings are included in notes payable in the balance sheets. Details of short-term borrowings were as follows:

	Short-term Debt at June 30, 2017		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)
Short-term bank debt	$ 17	2.9%	$ 29	3.1%	$ 36

(*) Average and maximum amounts are based upon daily balances during the three -month period ended June 30, 2017 .

Credit Rating Risk

At June 30, 2017 , Mississippi Power does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that have required or could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and/or Baa2 or below. These contracts are for physical electricity purchases and

sales, fuel transportation and storage, energy price risk management, and transmission. At June 30, 2017 , the maximum potential collateral requirements under these contracts at a rating of BBB and/or Baa2 or BBB- and/or Baa3 was not material. The maximum potential collateral requirements at a rating below BBB- and/or Baa3 equaled approximately $243 million.

Included in these amounts are certain agreements that could require collateral in the event that Alabama Power or Georgia Power has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of Mississippi Power to access capital markets, and would be likely to impact the cost at which it does so.

On March 1, 2017, Moody's downgraded the senior unsecured debt rating of Mississippi Power to Ba1 from Baa3.

On March 24, 2017, S&P revised its consolidated credit rating outlook for Southern Company and its subsidiaries (including Mississippi Power) from stable to negative.

On March 30, 2017, Fitch placed the ratings of Mississippi Power on rating watch negative.

On June 22, 2017, Moody's placed the ratings of Mississippi Power on review for downgrade.

Financing Activities

In March 2017, Mississippi Power issued a $9 million short-term bank note bearing interest at 5% per annum, which was repaid in April 2017.

In February 2017, Mississippi Power amended $551 million in promissory notes to Southern Company extending the maturity dates of the notes from December 1, 2017 to July 31, 2018. In the second quarter 2017, Mississippi Power borrowed an additional $40 million under a promissory note issued to Southern Company.

In June 2017, Southern Company made equity contributions totaling $1.0 billion to Mississippi Power. Mississippi Power used a portion of the proceeds to (i) prepay $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan, which matures on March 30, 2018; (ii) repay all of the $591 million outstanding principal amount of promissory notes to Southern Company; and (iii) repay a $10 million short-term bank loan.

SOUTHERN POWER COMPANY
AND SUBSIDIARY COMPANIES

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended June 30, 2017	For the Three Months Ended June 30, 2016	For the Six Months Ended June 30, 2017	For the Six Months Ended June 30, 2016
	(in millions)		*(in millions)*	
Operating Revenues:				
Wholesale revenues, non-affiliates	**$ 436**	$ 264	**$ 783**	$ 480
Wholesale revenues, affiliates	**90**	107	**190**	204
Other revenues	**3**	2	**6**	4
Total operating revenues	**529**	373	**979**	688
Operating Expenses:				
Fuel	**139**	96	**271**	187
Purchased power, non-affiliates	**29**	21	**54**	35
Purchased power, affiliates	**11**	2	**16**	8
Other operations and maintenance	**97**	86	**190**	162
Depreciation and amortization	**129**	81	**247**	154
Taxes other than income taxes	**12**	6	**24**	13
Total operating expenses	**417**	292	**802**	559
Operating Income	**112**	81	**177**	129
Other Income and (Expense):				
Interest expense, net of amounts capitalized	**(48)**	(22)	**(97)**	(43)
Other income (expense), net	**2**	1	**(2)**	1
Total other income and (expense)	**(46)**	(21)	**(99)**	(42)
Earnings Before Income Taxes	**66**	60	**78**	87
Income taxes (benefit)	**(38)**	(41)	**(90)**	(65)
Net Income	**104**	101	**168**	152
Less: Net income attributable to noncontrolling interests	**22**	12	**17**	13
Net Income Attributable to Southern Power	**$ 82**	$ 89	**$ 151**	$ 139

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended June 30, 2017	For the Three Months Ended June 30, 2016	For the Six Months Ended June 30, 2017	For the Six Months Ended June 30, 2016
	(in millions)		*(in millions)*	
Net Income	**$ 104**	$ 101	**$ 168**	$ 152
Other comprehensive income (loss):				
Qualifying hedges:				
Changes in fair value, net of tax of $24, $(15), $20, and $(15), respectively	**40**	(24)	**32**	(24)
Reclassification adjustment for amounts included in net income, net of tax of $(27), $8, $(30), and $8, respectively	**(45)**	13	**(48)**	14
Total other comprehensive income (loss)	**(5)**	(11)	**(16)**	(10)
Comprehensive Income	**99**	90	**152**	142
Less: Comprehensive income attributable to noncontrolling interests	**22**	12	**17**	13
Comprehensive Income Attributable to Southern Power	**$ 77**	$ 78	**$ 135**	$ 129

The accompanying notes as they relate to Southern Power are an integral part of these condensed consolidated financial statements.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Six Months Ended June 30,	
	2017	2016
	(in millions)	
Operating Activities:		
Net income	**$ 168**	$ 152
Adjustments to reconcile net income to net cash provided from operating activities —		
Depreciation and amortization, total	**264**	159
Deferred income taxes	**91**	(71)
Amortization of investment tax credits	**(28)**	(15)
Deferred revenues	**(34)**	(31)
Income taxes receivable, non-current	**(58)**	—
Other, net	**(1)**	9
Changes in certain current assets and liabilities —		
-Receivables	**(58)**	(76)
-Prepaid income taxes	**33**	(147)
-Other current assets	**20**	5
-Accounts payable	**(45)**	4
-Accrued taxes	**4**	62
-Other current liabilities	**(8)**	—
Net cash provided from operating activities	**348**	51
Investing Activities:		
Business acquisitions	**(1,020)**	(502)
Property additions	**(145)**	(1,281)
Change in construction payables	**(167)**	(137)
Payments pursuant to LTSAs	**(68)**	(43)
Investment in restricted cash	**(16)**	(646)
Distribution of restricted cash	**27**	649
Other investing activities	**(2)**	(25)
Net cash used for investing activities	**(1,391)**	(1,985)
Financing Activities:		
Increase in notes payable, net	**189**	695
Proceeds —		
Senior notes	—	1,241
Capital contributions from parent company	—	300
Distributions to noncontrolling interests	**(40)**	(11)
Capital contributions from noncontrolling interests	**73**	179
Purchase of membership interests from noncontrolling interests	—	(129)
Payment of common stock dividends	**(158)**	(136)
Other financing activities	**(21)**	(13)
Net cash provided from financing activities	**43**	2,126
Net Change in Cash and Cash Equivalents	**(1,000)**	192
Cash and Cash Equivalents at Beginning of Period	**1,099**	830
Cash and Cash Equivalents at End of Period	**$ 99**	$ 1,022
Supplemental Cash Flow Information:		
Cash paid (received) during the period for —		
Interest (net of $4 and $21 capitalized for 2017 and 2016, respectively)	**$ 113**	$ 42
Income taxes, net	**(117)**	115
Noncash transactions — Accrued property additions at end of period	**19**	108

The accompanying notes as they relate to Southern Power are an integral part of these condensed consolidated financial statements.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Assets	At June 30, 2017	At December 31, 2016
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 99**	$ 1,099
Receivables —		
Customer accounts receivable	**158**	102
Other accounts receivable	**37**	34
Affiliated	**65**	57
Fossil fuel stock	**15**	15
Materials and supplies	**349**	337
Prepaid income taxes	**41**	74
Other current assets	**26**	39
Total current assets	**790**	1,757
Property, Plant, and Equipment:		
In service	**13,731**	12,728
Less: Accumulated provision for depreciation	**1,689**	1,484
Plant in service, net of depreciation	**12,042**	11,244
Construction work in progress	**344**	398
Total property, plant, and equipment	**12,386**	11,642
Other Property and Investments:		
Intangible assets, net of amortization of $35 and $22 at June 30, 2017 and December 31, 2016, respectively	**423**	436
Total other property and investments	**423**	436
Deferred Charges and Other Assets:		
Prepaid LTSAs	**61**	101
Accumulated deferred income taxes	**536**	594
Income taxes receivable, non-current	**69**	11
Other deferred charges and assets — affiliated	**28**	13
Other deferred charges and assets — non-affiliated	**410**	615
Total deferred charges and other assets	**1,104**	1,334
Total Assets	**$ 14,703**	$ 15,169

The accompanying notes as they relate to Southern Power are an integral part of these condensed consolidated financial statements.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholders' Equity	**At June 30, 2017**	At December 31, 2016
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 909**	$ 560
Notes payable	**398**	209
Accounts payable —		
Affiliated	**68**	88
Other	**93**	278
Accrued taxes —		
Accrued income taxes	**35**	148
Other accrued taxes	**21**	7
Accrued interest	**25**	36
Acquisitions payable	**—**	461
Contingent consideration	**11**	46
Other current liabilities	**67**	70
Total current liabilities	**1,627**	1,903
Long-term Debt	**4,816**	5,068
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**174**	152
Accumulated deferred ITCs	**1,914**	1,839
Asset retirement obligations	**69**	64
Other deferred credits and liabilities	**238**	304
Total deferred credits and other liabilities	**2,395**	2,359
Total Liabilities	**8,838**	9,330
Redeemable Noncontrolling Interests	**51**	164
Common Stockholder's Equity:		
Common stock, par value $.01 per share —		
Authorized — 1,000,000 shares		
Outstanding — 1,000 shares	**—**	—
Paid-in capital	**3,671**	3,671
Retained earnings	**717**	724
Accumulated other comprehensive income	**19**	35
Total common stockholder's equity	**4,407**	4,430
Noncontrolling interests	**1,407**	1,245
Total stockholders' equity	**5,814**	5,675
Total Liabilities and Stockholders' Equity	**$ 14,703**	$ 15,169

The accompanying notes as they relate to Southern Power are an integral part of these condensed consolidated financial statements.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

SECOND QUARTER 2017 vs. SECOND QUARTER 2016
AND
YEAR-TO-DATE 2017 vs. YEAR-TO-DATE 2016

OVERVIEW

Southern Power constructs, acquires, owns, and manages power generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Power continually seeks opportunities to execute its strategy to create value through various transactions including acquisitions and sales of assets, construction and development of new generating facilities, and entry into PPAs primarily with investor-owned utilities, independent power producers, municipalities, and other load-serving entities. In general, Southern Power has constructed or acquired new generating capacity only after entering into or assuming long-term PPAs for the new facilities.

During the six months ended June 30, 2017 , Southern Power acquired or completed the construction of, and placed in service, approximately 498 MWs of solar and wind facilities. In addition, Southern Power continued developing its portfolio of wind projects as well as the construction to expand the Mankato natural gas facility by 345 MWs of capacity. Subsequent to June 30, 2017 , Southern Power acquired and commenced construction of Cactus Flats, a 148-MW wind facility. See FUTURE EARNINGS POTENTIAL – " Acquisitions " and " Construction Projects " herein for additional information.

At June 30, 2017 , Southern Power had an average investment coverage ratio of 91% through 2021 and 90% through 2026, with an average remaining contract duration of approximately 16 years. These ratios include the PPAs and capacity associated with facilities currently under construction and acquisitions discussed herein. See FUTURE EARNINGS POTENTIAL – " Power Sales Agreements " herein for additional information.

Southern Power continues to focus on several key performance indicators, including, but not limited to, peak season equivalent forced outage rate, contract availability, and net income.

RESULTS OF OPERATIONS

Net Income

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(7)	(7.9)	$12	8.6

Net income attributable to Southern Power for the second quarter 2017 was $82 million compared to $89 million for the corresponding period in 2016 . The decrease was primarily due to increased interest expense from debt issuances to fund acquisitions and construction and an increase in net income attributable to noncontrolling interests, significantly offset by additional operating income related to new generating facilities.

Net income attributable to Southern Power for year-to-date 2017 was $151 million compared to $139 million for the corresponding period in 2016 . The increase was primarily due to additional operating income from new generating facilities, as well as increased federal income tax benefits from wind PTCs, partially offset by increased interest expense from debt issuances to fund acquisitions and construction. For additional information on new generating facilities placed in service during 2016 and 2017, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – " Acquisitions " and " Construction Projects " of Southern Power in Item 7 of the Form 10-K and FUTURE EARNINGS POTENTIAL – " Acquisitions " and " Construction Projects " herein.

Operating Revenues

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$156	41.8	$291	42.3

Total operating revenues include PPA capacity revenues, which are derived primarily from long-term contracts involving natural gas and biomass generating facilities, and PPA energy revenues, which include sales from Southern Power's natural gas, biomass, solar, and wind facilities. To the extent Southern Power has capacity not contracted under a PPA, it may sell power into the wholesale market and, to the extent the generation assets are part of the IIC, as approved by the FERC, it may sell power into the power pool.

Natural Gas and Biomass Capacity and Energy Revenue

Capacity revenues generally represent the greatest contribution to net income and are designed to provide recovery of fixed costs plus a return on investment.

Energy is generally sold at variable cost or is indexed to published gas indices. Energy revenues will vary depending on the energy demand of Southern Power's customers and their generation capacity, as well as the market prices of wholesale energy compared to the cost of Southern Power's energy. Energy revenues also include fees for support services, fuel storage, and unit start charges. Increases and decreases in energy revenues under PPAs that are driven by fuel or purchased power prices are accompanied by an increase or decrease in fuel and purchased power costs and do not have a significant impact on net income.

Solar and Wind Energy Revenue

Southern Power's electricity sales from solar and wind generating facilities are predominantly through long-term PPAs that do not have a capacity charge. Customers either purchase the energy output of a dedicated renewable facility through an energy charge or pay a fixed price for electricity sold to the grid. As a result, Southern Power's ability to recover fixed and variable operations and maintenance expenses is dependent upon the level of energy generated from these facilities, which can be impacted by weather conditions, equipment performance, and other factors.

See FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" herein for additional information regarding Southern Power's PPAs.

Details of Southern Power's operating revenues were as follows:

	Second Quarter 2017	Second Quarter 2016	**Year-to-Date 2017**	Year-to-Date 2016
		(in millions)		
PPA capacity revenues	**$ 149**	$ 133	**$ 298**	$ 258
PPA energy revenues	**270**	168	**466**	285
Total PPA revenues	**419**	301	**764**	543
Non-PPA revenues	**107**	70	**209**	141
Other revenues	**3**	2	**6**	4
Total operating revenues	**$ 529**	$ 373	**$ 979**	$ 688

In the second quarter 2017 , total operating revenues were $529 million , reflecting a $156 million , or 42% , increase from the corresponding period in 2016 . The increase in operating revenues was primarily due to the following:

- PPA capacity revenues increased $16 million, or 12%, primarily due to new PPAs related to natural gas facilities and additional customer load requirements.
- PPA energy revenues increased $102 million, or 61%, primarily due to an $85 million increase in sales from new solar and wind facilities and a $20 million increase in sales from new natural gas PPAs and additional customer load requirements.
- Non-PPA revenues increased $37 million, or 53%, due to a $23 million increase in the volume of KWHs sold primarily from uncovered natural gas capacity through short-term opportunity sales, as well as a $14 million increase in the price of energy primarily due to increased natural gas prices.

For year-to-date 2017 , total operating revenues were $979 million , reflecting a $291 million , or 42% , increase from the corresponding period in 2016 . The increase in operating revenues was primarily due to the following:

- PPA capacity revenues increased $40 million, or 16%, primarily due to new PPAs related to natural gas facilities and additional customer load requirements.
- PPA energy revenues increased $181 million, or 64%, primarily due to a $137 million increase in sales from new solar and wind facilities and a $37 million increase in sales from new natural gas PPAs and additional customer load requirements.
- Non-PPA revenues increased $68 million, or 48%, due to a $48 million increase in the volume of KWHs sold primarily from uncovered natural gas capacity through short-term opportunity sales, as well as a $20 million increase in the price of energy primarily due to increased natural gas prices.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for Southern Power. In addition, Southern Power purchases a portion of its electricity needs from the wholesale market. Details of Southern Power's generation and purchased power were as follows:

	Second Quarter 2017	Second Quarter 2016	**Year-to-Date 2017**	Year-to-Date 2016
		(in billions of KWHs)		
Generation	**10.9**	9.1	**20.6**	16.7
Purchased power	**1.2**	0.9	**2.2**	1.5
Total generation and purchased power	**12.1**	10.0	**22.8**	18.2
Total generation and purchased power, excluding solar, wind, and tolling agreements	**5.6**	5.7	**10.5**	11.0

Southern Power's PPAs for natural gas and biomass generation generally provide that the purchasers are responsible for either procuring the fuel (tolling agreements) or reimbursing Southern Power for substantially all of the cost of fuel relating to the energy delivered under such PPAs. Consequently, changes in such fuel costs are generally accompanied by a corresponding change in related fuel revenues and do not have a significant impact on net income. Southern Power is responsible for the cost of fuel for generating units that are not covered under PPAs. Power from these generating units is sold into the wholesale market or into the power pool for capacity owned directly by Southern Power.

Purchased power expenses will vary depending on demand, availability, and the cost of generating resources throughout the Southern Company system and other contract resources. Load requirements are submitted to the power pool on an hourly basis and are fulfilled with the lowest cost alternative, whether that is generation owned by

Southern Power, an affiliate company, or external parties. Such purchased power costs are generally recovered through PPA revenues.

Details of Southern Power's fuel and purchased power expenses were as follows:

	Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
	(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
Fuel	$ 43	44.8	$ 84	44.9
Purchased power	17	73.9	27	62.8
Total fuel and purchased power expenses	$ 60		$ 111	

In the second quarter 2017 , total fuel and purchased power expenses increased $60 million, or 50.4%, compared to the corresponding period in 2016 . Fuel expense increased $43 million primarily due to a $51 million increase in the average cost of natural gas per KWH generated, partially offset by an $8 million decrease in the volume of KWHs generated, excluding solar, wind, and tolling agreements. Purchased power expense increased $17 million primarily due to a $10 million increase in the volume of KWHs purchased and a $6 million increase associated with the average cost of purchased power.

For year-to-date 2017 , total fuel and purchased power expenses increased $111 million, or 48.3%, compared to the corresponding period in 2016 . Fuel expense increased $84 million primarily due to a $105 million increase in the average cost of natural gas per KWH generated, partially offset by a $22 million decrease in the volume of KWHs generated, excluding solar, wind, and tolling agreements. Purchased power expense increased $27 million due to a $19 million increase in the volume of KWHs purchased and an $8 million increase associated with the average cost of purchased power.

Other Operations and Maintenance Expenses

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$11	12.8	$28	17.3

In the second quarter 2017 , other operations and maintenance expenses were $97 million compared to $86 million for the corresponding period in 2016 . The increase was primarily due to a $19 million increase associated with new solar, wind, and gas facilities and a $5 million increase associated with employee compensation and expenses in support of Southern Power's overall growth strategy, partially offset by a $9 million decrease in scheduled outage maintenance expenses and a $5 million decrease in non-outage operations and maintenance expenses.

For year-to-date 2017 , other operations and maintenance expenses were $190 million compared to $162 million for the corresponding period in 2016 . The increase was primarily due to a $35 million increase associated with new solar, wind, and gas facilities and a $10 million increase associated with employee compensation and expenses in support of Southern Power's overall growth strategy, partially offset by a $16 million decrease in scheduled outage maintenance expenses and a $4 million decrease in non-outage operations and maintenance expenses.

Depreciation and Amortization

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$48	59.3	$93	60.4

In the second quarter 2017 , depreciation and amortization was $129 million compared to $81 million for the corresponding period in 2016 . For year-to-date 2017 , depreciation and amortization was $247 million compared to

$154 million for the corresponding period in 2016 . The increases were primarily due to new solar, wind, and gas facilities placed in service.

Interest Expense, net of Amounts Capitalized

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$26	118.2	$54	125.6

In the second quarter 2017 , interest expense, net of amounts capitalized was $48 million compared to $22 million for the corresponding period in 2016 . The increase was primarily due to an increase of $16 million in interest expense related to additional debt issued in 2016, primarily to fund Southern Power's growth strategy and continuous construction program, as well as a $9 million decrease in capitalized interest associated with completing construction of and placing in service solar facilities.

For year-to-date 2017 , interest expense, net of amounts capitalized was $97 million compared to $43 million for the corresponding period in 2016 . The increase was primarily due to an increase of $36 million in interest expense related to additional debt issued in 2016, primarily to fund Southern Power's growth strategy and continuous construction program, as well as a $17 million decrease in capitalized interest associated with completing construction of and placing in service solar facilities.

Other Income (Expense), Net

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$1	100.0	$(3)	(300.0)

In the second quarter 2017 , other income (expense), net was $2 million compared to $1 million for the corresponding period in 2016 . For year-to-date 2017 , other income (expense), net was $(2) million compared to $1 million for the corresponding period in 2016 . The changes include increases of $99 million and $116 million from currency losses arising from translation of €1.1 billion euro-denominated fixed-rate notes into U.S. dollars for the second quarter and year-to-date 2017, respectively, fully offset by an equal change in gains on the foreign currency hedges that were reclassified from accumulated OCI into earnings. See Note (H) to the Condensed Financial Statements herein for additional information.

Income Taxes (Benefit)

Second Quarter 2017 vs. Second Quarter 2016		Year-to-Date 2017 vs. Year-to-Date 2016	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$3	7.3	$(25)	(38.5)

In the second quarter 2017 , income tax benefit was $38 million compared to $41 million for the corresponding period in 2016 . The decrease was primarily due to a $29 million decrease in ITC benefits, partially offset by a $27 million increase in wind PTC benefits.

For year-to-date 2017 , income tax benefit was $90 million compared to $65 million for the corresponding period in 2016 . The increase was primarily due to a $57 million increase in wind PTC benefits, a $4 million increase resulting from state apportionment rate changes, and a $4 million increase related to lower pre-tax earnings, partially offset by a $41 million decrease in ITC benefits.

See Note (G) to the Condensed Financial Statements herein for additional information on income taxes and Note 1 to the financial statements of Southern Power under "Income and Other Taxes" in Item 8 of the Form 10-K for additional information on ITCs.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Southern Power's future earnings potential. The level of Southern Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Southern Power's competitive wholesale business. These factors include: Southern Power's ability to achieve sales growth while containing costs; regulatory matters; creditworthiness of customers; total generating capacity available in Southern Power's market areas; the successful remarketing of capacity as current contracts expire; Southern Power's ability to execute its growth strategy, including successful additional investments in renewable and other energy projects, and to develop and construct generating facilities. Current proposals related to potential federal tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals, including any potential changes to the availability or realizability of ITCs and PTCs, is dependent on the final form of any legislation enacted and the related transition rules, and cannot be determined at this time, but could have a material impact on Southern Power's consolidated financial statements.

Demand for electricity is primarily driven by economic growth. The pace of economic growth and electricity demand may be affected by changes in regional and global economic conditions, as well as renewable portfolio standards, which may impact future earnings.

Other factors that could influence future earnings include weather, demand, cost of generation from facilities within the power pool, and operational limitations. For additional information relating to these factors, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Southern Power in Item 7 of the Form 10-K.

Power Sales Agreements

See BUSINESS – "The Southern Company System – Southern Power" in Item 1 of the Form 10-K for additional information regarding Southern Power's PPAs. Generally, under the solar and wind generation PPAs, the purchasing party retains the right to keep or resell the renewable energy credits.

At June 30, 2017 , Southern Power's average investment coverage ratio for its generating assets, based on the ratio of investment under contract to total investment using the respective generation facilities' net book value (or expected in-service value for facilities under construction) as the investment amount, was 91% through 2021 and 90% through 2026, with an average remaining contract duration of approximately 16 years.

Environmental Matters

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Power in Item 7 of the Form 10-K for information on the development by federal and state environmental regulatory agencies of additional control strategies for emissions of air pollution from industrial sources, including electric generating facilities. Compliance with possible additional federal or state legislation or regulations related to global climate change, air quality, water quality, or other environmental and health concerns could also significantly affect Southern Power. While Southern Power's PPAs generally contain provisions that permit charging the counterparty with some of the new costs incurred as a result of changes in environmental laws and regulations, the full impact of any such legislative or regulatory changes cannot be determined at this time.

Environmental Statutes and Regulations

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Southern Power in Item 7 of the Form 10-K for additional information regarding the final effluent guidelines rule.

On April 25, 2017, the EPA published a notice announcing it would reconsider the effluent guidelines rule, which had been finalized in November 2015. On June 6, 2017, the EPA proposed a rule establishing a stay of the compliance deadlines for certain effluent limitations and pretreatment standards under the rule.

The ultimate outcome of this matter cannot be determined at this time.

Global Climate Issues

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" of Southern Power in Item 7 of the Form 10-K for additional information.

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. The executive order specifically directs the EPA to review the Clean Power Plan and final greenhouse gas emission standards for new, modified, and reconstructed electric generating units and, if appropriate, take action to suspend, revise, or rescind those rules.

On June 1, 2017, the U.S. President announced that the United States will withdraw from the non-binding Paris Agreement and begin renegotiation of its terms.

The ultimate outcome of these matters cannot be determined at this time.

FERC Matters

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters" of Southern Power in Item 7 of the Form 10-K for additional information regarding the traditional electric operating companies' and Southern Power's market power proceeding and amendment to their market-rate tariff.

On May 17, 2017, the FERC accepted the traditional electric operating companies' and Southern Power's compliance filing accepting the terms of the FERC's February 2, 2017 order regarding an amendment by the traditional electric operating companies and Southern Power to their market-based rate tariff. While the FERC's order references the traditional electric operating companies' and Southern Power's market power proceeding, it remains a separate, ongoing matter.

Acquisitions

During the six months ended June 30, 2017 , in accordance with Southern Power's overall growth strategy, Southern Renewable Partnerships, LLC (SRP), one of Southern Power's wholly-owned subsidiaries, acquired the Bethel wind facility. Acquisition-related costs were expensed as incurred and were not material. See Note (I) to the Condensed Financial Statements under " Southern Power " herein and MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Power in Item 7 of the Form 10-K for additional information.

Project Facility	Resource	Approximate Nameplate Capacity (*MW*)	Location	Percentage Ownership	Actual COD	PPA Counterparties	PPA Contract Period
Bethel	Wind	276	Castro County, TX	100%	January 2017	Google Energy, LLC	12 years

The aggregate amounts of revenue and net income, excluding impacts from PTCs, recognized by Southern Power related to the Bethel facility included in the condensed consolidated statements of income for year-to-date 2017 were immaterial . The Bethel facility did not have operating revenues or activities prior to completion of construction and the assets being placed in service; therefore, supplemental pro forma information for the comparable 2016 period is not meaningful and has been omitted.

Subsequent to June 30, 2017, Southern Power acquired a 100% ownership interest in and commenced construction of the Cactus Flats 148-MW wind facility, the majority of which is covered by two PPAs, which expire in 2030 and

2033. The facility is expected to be placed in service in mid-2018. The ultimate outcome of this matter cannot be determined at this time.

Construction Projects

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Acquisitions" and "Construction Projects" of Southern Power in Item 7 of the Form 10-K and FINANCIAL CONDITION AND LIQUIDITY – " Capital Requirements and Contractual Obligations " herein for additional information.

Construction Projects Completed and in Progress

During the six months ended June 30, 2017 , in accordance with its overall growth strategy, Southern Power completed construction of and placed in service, or continued construction of, the projects set forth in the following table. Through June 30, 2017 , total costs of construction incurred for these projects were $421 million , of which $49 million remained in CWIP for the Mankato facility acquired in 2016. Total aggregate construction costs, excluding the acquisition costs, are expected to be $170 million to $190 million for the Mankato facility. The ultimate outcome of this matter cannot be determined at this time.

Project Facility	Resource	Approximate Nameplate Capacity (*MW*)	Location	Actual/Expected COD	PPA Counterparties	PPA Contract Period
Projects Completed During the Six Months Ended June 30, 2017						
East Pecos	Solar	120	Pecos County, TX	March 2017	Austin Energy	15 years
Lamesa	Solar	102	Dawson County, TX	April 2017	City of Garland, Texas	15 years
Project Under Construction as of June 30, 2017						
Mankato	Natural Gas	345	Mankato, MN	Second quarter 2019	Northern States Power Company	20 years

Development Projects

In December 2016, as part of Southern Power's renewable development strategy, SRP entered into a joint development agreement with Renewable Energy Systems Americas, Inc. to develop and construct approximately 3,000 MWs of wind projects. Also in December 2016, Southern Power signed agreements and made payments to purchase wind turbine equipment from Siemens Wind Power, Inc. and Vestas-American Wind Technology, Inc. to be used for construction of the facilities. All of the wind turbine equipment was delivered by April 2017, which allows the projects to qualify for 100% PTCs for 10 years following their expected commercial operation dates between 2018 and 2020. The ultimate outcome of these matters cannot be determined at this time.

Income Tax Matters

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Income Tax Matters" of Southern Power in Item 7 of the Form 10-K and Note (G) to the Condensed Financial Statements herein for additional information.

Other Matters

Southern Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Southern Power is subject to certain claims and legal actions arising in the ordinary course of business. Southern Power's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has occurred throughout the

U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation against Southern Power cannot be predicted at this time; however, for current proceedings not specifically reported in Note (B) to the Condensed Financial Statements herein , management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Power's financial statements.

During 2015, Southern Power indirectly acquired a 51% membership interest in RE Roserock LLC (Roserock), the owner of the Roserock facility in Pecos County, Texas, which was under construction by Recurrent Energy, LLC and was subsequently placed in service in November 2016. Prior to placing the facility in service, certain solar panels were damaged during installation. While the facility currently is generating energy consistent with operational expectations and PPA obligations, Southern Power is pursuing remedies under its insurance policies and other contracts to repair or replace these solar panels. In connection therewith, Southern Power is withholding payments of approximately $26 million from the construction contractor, who has placed a lien on the Roserock facility for the same amount. The amounts withheld are included in other accounts payable and other current liabilities on Southern Power's consolidated balance sheets. On May 18, 2017, Roserock filed a lawsuit in the state district court in Pecos County, Texas, against X.L. America, Inc. (XL) and North American Elite Insurance Company (North American Elite) seeking recovery from an insurance policy for damages resulting from a hail storm and certain installation practices by the construction contractor, McCarthy Building Companies, Inc. (McCarthy). On May 19, 2017, Roserock filed a separate lawsuit against McCarthy in the state district court in Travis County, Texas alleging breach of contract and breach of warranty for the damages sustained at the Roserock facility, which has since been moved to the U.S. District Court for the Western District of Texas. On May 22, 2017, McCarthy filed a lawsuit against Roserock, Array Technologies, Inc., Canadian Solar (USA), Inc., XL, and North American Elite in the U.S. District Court for the Western District of Texas alleging, among other things, breach of contract, and requesting foreclosure of mechanic's liens against Roserock. On July 18, 2017, the U.S. District Court for the Western District of Texas consolidated the two pending lawsuits. Southern Power intends to vigorously pursue and defend these matters, the ultimate outcome of which cannot be determined at this time.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Southern Power prepares its consolidated financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Southern Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Southern Power'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. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Southern Power in Item 7 of the Form 10-K for a complete discussion of Southern Power's critical accounting policies and estimates related to Revenue Recognition, Impairment of Long-Lived Assets and Intangibles, Acquisition Accounting, and ITCs.

Recently Issued Accounting Standards

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 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.

While Southern Power expect s most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of all revenue arrangements. However, given Southern Power's core activities of selling

generation capacity and energy to high credit rated customers, Southern Power currently does not expect the new standard to have a significant impact to net income. Southern Power's ongoing evaluation of revenue streams and related contracts includes the evaluation of identified revenue streams tied to longer-term contractual arrangements, such as certain capacity and energy payments under PPAs that are expected to be excluded from the scope of ASC 606 and included in the scope of the current leasing guidance (ASC 840).

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. Southern Power intends to use the modified retrospective method of adoption effective January 1, 2018. Southern Power has also elected to utilize practical expedients which allow 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, disclosures will include comparative information on 2018 financial statement line items under current guidance. While the adoption of ASC 606, including the cumulative-effect adjustment, is not expected to have a material impact on either the timing or amount of revenues recognized in Southern Power's financial statements, Southern Power will continue to evaluate the requirements, as well as any additional clarifying guidance that may be issued.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Overview" of Southern Power in Item 7 of the Form 10-K for additional information. Southern Power's financial condition remained stable at June 30, 2017 . Southern Power intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit agreements as needed to meet future capital and liquidity needs. See " Sources of Capital " herein for additional information on lines of credit.

Net cash provided from operating activities totaled $348 million for the first six months of 2017 compared to $51 million for the first six months of 2016 . The increase in net cash provided from operating activities was primarily due to an increase in energy sales arising from new solar and wind facilities and a decrease in income taxes paid, partially offset by an increase in interest paid. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Bonus Depreciation" of Southern Power in Item 7 of the Form 10-K for additional information. Net cash used for investing activities totaled $1.4 billion for the first six months of 2017 primarily due to payments for renewable acquisitions and the construction of generating facilities. See FUTURE EARNINGS POTENTIAL – " Acquisitions " and " Construction Projects " herein for additional information. Net cash provided from financing activities totaled $43 million for the first six months of 2017 primarily due to notes payable and contributions from noncontrolling interests, partially offset by dividends to Southern Company and distributions to noncontrolling interests. Cash flows from financing activities may vary from period to period based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for the first six months of 2017 include a $1.0 billion decrease in cash and cash equivalents and a $798 million increase in property, plant, and equipment in-service primarily related to acquisitions, as well as a $54 million decrease in CWIP primarily due to East Pecos and Lamesa being placed in service, partially offset by equipment purchased for wind construction projects. See FUTURE EARNINGS POTENTIAL – " Acquisitions " and " Construction Projects " herein for additional information.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Power in Item 7 of the Form 10-K for a description of Southern Power's capital requirements for its construction program, scheduled maturities of long-term debt, as well as the related interest, derivative obligations, leases, unrecognized tax benefits, and other purchase

commitments. Approximately $909 million will be required to repay maturities of long-term debt through June 30, 2018 .

Southern Power's construction program includes estimates for potential plant acquisitions, new construction and development, capital improvements, and work to be performed under LTSAs and is subject to periodic review and revision. Planned expenditures for plant acquisitions may vary materially due to market opportunities and Southern Power's ability to execute its growth strategy. Actual capital costs may vary from these estimates because of numerous factors such as: changes in business conditions; changes in the expected environmental compliance program; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in FERC rules and regulations; changes in load projections; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. See Note (I) to the Condensed Financial Statements herein for additional information.

Sources of Capital

Southern Power plans to obtain the funds required for acquisitions, construction, development, and other purposes from operating cash flows, short-term debt, securities issuances, term loans, tax equity partnership contributions, 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. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Southern Power in Item 7 of the Form 10-K for additional information.

As of June 30, 2017, Southern Power's current liabilities exceeded current assets by $837 million due to long-term debt maturing in the next 12 months, the use of short-term debt as a funding source, and construction payables, as well as fluctuations in cash needs, due to both seasonality and the stage of acquisitions and construction projects. In 2017 , Southern Power expects to utilize the debt capital markets, bank term loans, and commercial paper markets as the source of funds for the majority of its debt maturities.

As of June 30, 2017 , Southern Power had cash and cash equivalents of approximately $99 million .

Southern Power believes the need for working capital can be adequately met by utilizing the commercial paper program, the Facility (as defined below), bank term loans, and operating cash flows.

Southern Power's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities, for general corporate purposes, and to finance maturing debt. Commercial paper is included in notes payable on the condensed consolidated balance sheet at June 30, 2017.

Details of commercial paper were as follows:

	Short-term Debt at June 30, 2017		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)*
Commercial paper	$ 398	1.5%	$ 328	1.3%	$ 419

(*) Average and maximum amounts are based upon daily balances during the three -month period ended June 30, 2017 .

At June 30, 2017 , Southern Power had a committed credit facility (Facility) of $750 million , of which $75 million has been used for letters of credit and $675 million remains unused. In May 2017, Southern Power amended the Facility, which, among other things, extended the maturity date from 2020 to 2022 and increased Southern Power's borrowing ability under this Facility to $750 million from $600 million. Proceeds from the Facility may be used for working capital and general corporate purposes as well as liquidity support for Southern Power's commercial paper program. Subject to applicable market conditions, Southern Power expects to renew or replace the Facility, as

needed, prior to expiration. In connection therewith, Southern Power may extend the maturity date and/or increase or decrease the lending commitment thereunder. See Note 6 to the financial statements of Southern Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under " Bank Credit Arrangements " herein for additional information.

The Facility, as well as Southern Power's term loan agreement, contains a covenant that limits the ratio of debt to capitalization (as defined in the Facility) to a maximum of 65% and contains a cross-default provision that is restricted only to indebtedness of Southern Power. For purposes of this definition, debt excludes any project debt incurred by certain subsidiaries of Southern Power to the extent such debt is non-recourse to Southern Power, and capitalization excludes the capital stock or other equity attributable to such subsidiary. Southern Power is currently in compliance with all covenants in the Facility.

In December 2016, Southern Power entered into an agreement for a $120 million continuing letter of credit facility for standby letters of credit expiring in 2019. At June 30, 2017 , the total amount available under this letter of credit facility was $62 million.

Southern Power's subsidiaries do not borrow under the commercial paper program and are not parties to, and do not borrow under, the Facility or the continuing letter of credit facility.

Credit Rating Risk

Southern Power does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and/or Baa2, or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, energy price risk management, transmission, and foreign currency risk management.

The maximum potential collateral requirements under these contracts at June 30, 2017 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and/or Baa2	$ 38
At BBB- and/or Baa3	$ 392
At BB+ and/or Ba1 (*)	$ 1,127

(*) Any additional credit rating downgrades at or below BB- and/or Ba3 could increase collateral requirements up to an additional $38 million.

Included in these amounts are certain agreements that could require collateral in the event that Alabama Power or Georgia Power has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of Southern Power to access capital markets and would be likely to impact the cost at which it does so.

In addition, Southern Power has a PPA that could require collateral, but not accelerated payment, in the event of a downgrade of Southern Power's credit. The PPA requires credit assurances without stating a specific credit rating. The amount of collateral required would depend upon actual losses resulting from a credit downgrade.

On March 24, 2017, S&P revised its consolidated credit rating outlook for Southern Company and its subsidiaries (including Southern Power) from stable to negative.

Financing Activities

Southern Power did not issue or redeem any securities during the six months ended June 30, 2017.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Southern Power 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.

SOUTHERN COMPANY GAS
AND SUBSIDIARY COMPANIES

SOUTHERN COMPANY GAS AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	Successor	Predecessor	**Successor**	Predecessor
	For the Three Months Ended June 30, 2017	For the Three Months Ended June 30, 2016	**For the Six Months Ended June 30, 2017**	For the Six Months Ended June 30, 2016
	(in millions)	*(in millions)*	*(in millions)*	*(in millions)*
Operating Revenues:				
Natural gas revenues (includes revenue taxes of $19, $17, $67, and $57 for the periods presented, respectively)	**$ 684**	$ 539	**$ 2,214**	$ 1,841
Other revenues	**32**	32	**62**	64
Total operating revenues	**716**	571	**2,276**	1,905
Operating Expenses:				
Cost of natural gas	**232**	184	**951**	755
Cost of other sales	**6**	7	**13**	14
Other operations and maintenance	**213**	213	**467**	454
Depreciation and amortization	**125**	104	**244**	206
Taxes other than income taxes	**44**	37	**114**	99
Merger-related expenses	**—**	53	**—**	56
Total operating expenses	**620**	598	**1,789**	1,584
Operating Income (Loss)	**96**	(27)	**487**	321
Other Income and (Expense):				
Earnings from equity method investments	**29**	1	**68**	2
Interest expense, net of amounts capitalized	**(48)**	(48)	**(94)**	(96)
Other income (expense), net	**3**	2	**7**	5
Total other income and (expense)	**(16)**	(45)	**(19)**	(89)
Earnings (Loss) Before Income Taxes	**80**	(72)	**468**	232
Income taxes (benefit)	**31**	(24)	**180**	87
Net Income (Loss)	**49**	(48)	**288**	145
Less: Net income attributable to noncontrolling interest	**—**	3	**—**	14
Net Income (Loss) Attributable to Southern Company Gas	**$ 49**	$ (51)	**$ 288**	$ 131

The accompanying notes as they relate to Southern Company Gas are an integral part of these condensed consolidated financial statements.

SOUTHERN COMPANY GAS AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	Successor	Predecessor	Successor	Predecessor
	For the Three Months Ended June 30, 2017	For the Three Months Ended June 30, 2016	**For the Six Months Ended June 30, 2017**	For the Six Months Ended June 30, 2016
	(in millions)	*(in millions)*	*(in millions)*	*(in millions)*
Net Income (Loss)	**$ 49**	$ (48)	**$ 288**	$ 145
Other comprehensive income (loss):				
Qualifying hedges:				
Changes in fair value, net of tax of $(1), $(7), $(2), and $(23), respectively	**(1)**	(12)	**(2)**	(41)
Reclassification adjustment for amounts included in net income, net of tax of $-, $-, $-, and $-, respectively	**—**	2	**—**	1
Pension and other postretirement benefit plans:				
Reclassification adjustment for amounts included in net income, net of tax of $-, $2, $-, and $4, respectively	**—**	2	**(1)**	5
Total other comprehensive income (loss)	**(1)**	(8)	**(3)**	(35)
Comprehensive Income (Loss)	**48**	(56)	**285**	110
Less: Comprehensive income attributable to noncontrolling interest	**—**	3	**—**	14
Comprehensive Income (Loss) Attributable to Southern Company Gas	**$ 48**	$ (59)	**$ 285**	$ 96

The accompanying notes as they relate to Southern Company Gas are an integral part of these condensed consolidated financial statements.

SOUTHERN COMPANY GAS AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Successor	Predecessor
	For the Six Months Ended June 30, 2017	For the Six Months Ended June 30, 2016
	(in millions)	*(in millions)*
Operating Activities:		
Net income	**$ 288**	$ 145
Adjustments to reconcile net income to net cash provided from operating activities —		
Depreciation and amortization, total	**244**	206
Deferred income taxes	**144**	8
Stock based compensation expense	**19**	20
Hedge settlements	**—**	(26)
Mark-to-market adjustments	**(49)**	162
Other, net	**(53)**	(77)
Changes in certain current assets and liabilities —		
-Receivables	**420**	181
-Natural gas for sale, net of temporary LIFO liquidation	**223**	273
-Prepaid income taxes	**24**	151
-Other current assets	**(12)**	37
-Accounts payable	**(102)**	43
-Accrued taxes	**(8)**	41
-Accrued compensation	**(12)**	(21)
-Other current liabilities	**25**	(30)
Net cash provided from operating activities	**1,151**	1,113
Investing Activities:		
Property additions	**(684)**	(509)
Cost of removal, net of salvage	**(25)**	(32)
Change in construction payables, net	**23**	(7)
Investment in unconsolidated subsidiaries	**(111)**	(14)
Other investing activities	**16**	3
Net cash used for investing activities	**(781)**	(559)
Financing Activities:		
Decrease in notes payable, net	**(631)**	(896)
Proceeds —		
First mortgage bonds	**—**	250
Capital contributions from parent company	**57**	—
Senior notes	**450**	350
Redemptions and repurchases — First mortgage bonds	**—**	(125)
Distributions to noncontrolling interest	**—**	(19)
Payment of common stock dividends	**(221)**	(128)
Other financing activities	**(6)**	10
Net cash used for financing activities	**(351)**	(558)
Net Change in Cash and Cash Equivalents	**19**	(4)
Cash and Cash Equivalents at Beginning of Period	**19**	19
Cash and Cash Equivalents at End of Period	**$ 38**	$ 15
Supplemental Cash Flow Information:		
Cash paid (received) during the period for —		
Interest (net of $7 and $3 capitalized for 2017 and 2016, respectively)	**$ 105**	$ 119
Income taxes, net	**20**	(100)
Noncash transactions — Accrued property additions at end of period	**84**	41

The accompanying notes as they relate to Southern Company Gas are an integral part of these condensed consolidated financial statements.

SOUTHERN COMPANY GAS AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Assets	At June 30, 2017	At December 31, 2016
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 38**	$ 19
Receivables —		
Energy marketing receivables	**482**	623
Customer accounts receivable	**270**	364
Unbilled revenues	**69**	239
Other accounts and notes receivable	**63**	76
Accumulated provision for uncollectible accounts	**(35)**	(27)
Materials and supplies	**24**	26
Natural gas for sale	**477**	631
Prepaid expenses	**69**	80
Assets from risk management activities, net of collateral	**114**	128
Other regulatory assets, current	**72**	81
Other current assets	**20**	10
Total current assets	**1,663**	2,250
Property, Plant, and Equipment:		
In service	**14,850**	14,508
Less: Accumulated depreciation	**4,550**	4,439
Plant in service, net of depreciation	**10,300**	10,069
Construction work in progress	**779**	496
Total property, plant, and equipment	**11,079**	10,565
Other Property and Investments:		
Goodwill	**5,967**	5,967
Equity investments in unconsolidated subsidiaries	**1,610**	1,541
Other intangible assets, net of amortization of $80 and $34 at June 30, 2017 and December 31, 2016, respectively	**320**	366
Miscellaneous property and investments	**21**	21
Total other property and investments	**7,918**	7,895
Deferred Charges and Other Assets:		
Other regulatory assets, deferred	**963**	973
Other deferred charges and assets	**186**	170
Total deferred charges and other assets	**1,149**	1,143
Total Assets	**$ 21,809**	$ 21,853

The accompanying notes as they relate to Southern Company Gas are an integral part of these condensed consolidated financial statements.

SOUTHERN COMPANY GAS AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	**At June 30, 2017**	At December 31, 2016
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 22**	$ 22
Notes payable	**626**	1,257
Energy marketing trade payables	**534**	597
Accounts payable	**327**	348
Customer deposits	**134**	153
Accrued taxes —		
Accrued income taxes	**23**	26
Other accrued taxes	**63**	68
Accrued interest	**50**	48
Accrued compensation	**45**	58
Liabilities from risk management activities, net of collateral	**20**	62
Other regulatory liabilities, current	**146**	102
Accrued environmental remediation, current	**63**	69
Temporary LIFO liquidation	**69**	—
Other current liabilities	**113**	108
Total current liabilities	**2,235**	2,918
Long-term Debt	**5,677**	5,259
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**2,091**	1,975
Employee benefit obligations	**432**	441
Other cost of removal obligations	**1,638**	1,616
Accrued environmental remediation, deferred	**353**	357
Other regulatory liabilities, deferred	**50**	51
Other deferred credits and liabilities	**91**	127
Total deferred credits and other liabilities	**4,655**	4,567
Total Liabilities	**12,567**	12,744
Common Stockholder's Equity:		
Common stock, par value $0.01 per share —		
Authorized — 100 million shares		
Outstanding — 100 shares	**—**	—
Paid in capital	**9,164**	9,095
Retained earnings (accumulated deficit)	**55**	(12)
Accumulated other comprehensive income	**23**	26
Total common stockholder's equity	**9,242**	9,109
Total Liabilities and Stockholder's Equity	**$ 21,809**	$ 21,853

The accompanying notes as they relate to Southern Company Gas are an integral part of these condensed consolidated financial statements.

SOUTHERN COMPANY GAS AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

Southern Company Gas is an energy services holding company whose primary business is the distribution of natural gas through utilities in seven states – Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee, and Maryland. Southern Company Gas and its subsidiaries are also involved in several other complementary businesses.

Southern Company Gas has four reportable segments – gas distribution operations, gas marketing services, wholesale gas services, and gas midstream operations – and one non-reportable segment – all other. For additional information on these segments, see Note (K) to the Condensed Financial Statements herein and "BUSINESS – Southern Company Gas" in Item 1 of the Form 10-K.

Many factors affect the opportunities, challenges, and risks of Southern Company Gas' business. These factors include the ability to maintain constructive regulatory environments, to maintain and grow natural gas sales, and to effectively manage and secure timely recovery of costs. Southern Company Gas 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 Southern Company Gas for the foreseeable future.

Merger and Acquisition Activities

On July 1, 2016, Southern Company Gas completed the Merger, which was accounted for by Southern Company using the acquisition method of accounting whereby the assets acquired and liabilities assumed were recognized at fair value as of the acquisition date. Pushdown accounting was applied to create a new cost basis for Southern Company Gas assets, liabilities, and equity as of the acquisition date. Accordingly, the successor financial statements reflect a new basis of accounting and successor and predecessor period financial results (separated by a heavy black line) are presented, but are not comparable. As a result of the application of acquisition accounting, certain discussions herein include disclosure of the predecessor and successor periods. See Note (I) to the Condensed Financial Statements herein for additional information relating to the Merger.

In September 2016, Southern Company Gas paid approximately $1.4 billion to acquire a 50% equity interest in SNG. On March 31, 2017, Southern Company Gas made an additional $50 million contribution to maintain its 50% equity interest in SNG. Southern Company Gas recorded equity investment income of $24 million and $58 million from this investment in the second quarter and year-to-date 2017 , respectively. See Note (J) to the Condensed Financial Statements herein and Notes 4 and 11 to the financial statements of Southern Company Gas under "Equity Method Investments – SNG" and "Investment in SNG," respectively, in Item 8 of the Form 10-K for additional information.

In October 2016, Southern Company Gas completed its purchase of Piedmont's 15% interest in SouthStar, which eliminated the noncontrolling interest associated with SouthStar. See Note 4 to the financial statements of Southern Company Gas under "Variable Interest Entities" in Item 8 of the Form 10-K for additional information.

Operating Metrics

Southern Company Gas continues to focus on several operating metrics, including Heating Degree Days, customer count, and volumes of natural gas sold. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATIONS – "Operating Metrics" of Southern Company Gas in Item 7 of the Form 10-K.

Southern Company Gas measures weather and the effect on its business using Heating Degree Days. Generally, increased Heating Degree Days result in higher demand for natural gas on Southern Company Gas' distribution system. With the exception of Southern Company Gas' utilities in Illinois and Florida, Southern Company Gas has various regulatory mechanisms, such as weather normalization mechanisms, which limit its exposure to weather changes within typical ranges in each of its utilities' respective service territory. However, the utility customers in Illinois and the gas marketing services customers primarily in Georgia can be impacted by warmer- or colder-than-normal weather. Southern Company Gas utilizes weather hedges at gas distribution operations and gas marketing services to reduce negative earnings impact in the event of warmer-than-normal weather, while retaining all of the

earnings upside in the event of colder-than-normal weather for gas distribution operations in Illinois and most of the earnings upside for gas marketing services.

The number of customers at gas distribution operations and energy customers at gas marketing services can be impacted by natural gas prices, economic conditions, and competition from alternative fuels. Gas marketing services' customers are primarily located in Georgia and Illinois.

Southern Company Gas' natural gas volume metrics for gas distribution operations and gas marketing services illustrate the effects of weather and customer demand for natural gas. Wholesale gas services' physical sales volumes represent the daily average natural gas volumes sold to its customers.

Seasonality of Results

During the months of November through March, natural gas usage and operating revenues are generally higher, as more customers are connected to the gas distribution systems and natural gas usage is higher in periods of colder weather. Occasionally in the summer, wholesale gas services' operating revenues are impacted due to peak usage by power generators in response to summer energy demands. Southern Company Gas' base operating expenses, excluding cost of natural gas, bad debt expense, and certain incentive compensation costs, are incurred relatively evenly during a year. Seasonality also affects the comparison of certain balance sheet items across quarters, including receivables, unbilled revenues, natural gas for sale, and notes payable. However, these items are comparable when reviewing Southern Company Gas' annual results. Operating results for the interim periods presented are not necessarily indicative of annual results and can vary significantly from quarter to quarter.

RESULTS OF OPERATIONS

Net Income

Net income attributable to Southern Company Gas for the successor second quarter 2017 and net loss attributable to Southern Company Gas for the predecessor second quarter 2016 were $49 million and $51 million , respectively. Net income attributable to Southern Company Gas for the successor year-to-date 2017 and the predecessor year-to-date 2016 was $288 million and $131 million , respectively.

As a result of purchasing the remaining interest in SouthStar in October 2016, all net income was attributable to Southern Company Gas in the successor period. Net income for the successor second quarter 2017 was negatively impacted by $5 million due to the pushdown of acquisition accounting related to the Merger and included $10 million in after-tax earnings from the SNG investment, net of related interest expense. Also reflected in net income was an increase of $12 million, after tax, from additional infrastructure replacement programs at gas distribution operations, net of increased depreciation and a base rate increase at Atlanta Gas Light effective March 1, 2017. The successor second quarter 2017 also included $11 million in after-tax losses from commercial activity and $8 million in after-tax mark-to-market gains at wholesale gas services.

Net loss attributable to Southern Company Gas for the predecessor second quarter 2016 included $39 million in after-tax Merger-related expenses, as well as $5 million in after-tax losses from commercial activity at wholesale gas services and $50 million in net after-tax mark-to-market losses at wholesale gas services and gas marketing services due to changes in natural gas price volatility in the period.

Net income attributable to Southern Company Gas for the successor year-to-date 2017 was negatively impacted by $2 million due to the pushdown of acquisition accounting related to the Merger and included $25 million in after-tax earnings from the SNG investment, net of related interest expense. The successor year-to-date 2017 included an increase of $19 million, after tax, from additional infrastructure replacement programs at gas distribution operations, net of increased depreciation and a base rate increase at Atlanta Gas Light effective March 1, 2017. The successor year-to-date 2017 also included $41 million in after-tax gains from commercial activity at wholesale gas services, $27 million in net after-tax mark-to-market gains at wholesale gas services and gas marketing services, and a reduction of $9 million, after tax, resulting from warmer-than-normal weather, net of hedging.

Net income attributable to Southern Company Gas for the predecessor year-to-date 2016 included $41 million in after-tax Merger-related expenses and $21 million in after-tax mark-to-market gains from commercial activity at

wholesale gas services. Also reflected in net income was $38 million in net after-tax mark-to-market losses at wholesale gas services and gas marketing services and a decrease of $5 million, after tax, resulting from warmer-than-normal weather, net of hedging.

Natural Gas Revenues

Natural gas revenues for the successor second quarter 2017 and the predecessor second quarter 2016 were $684 million and $539 million , respectively. Natural gas revenues for the successor year-to-date 2017 and the predecessor year-to-date 2016 were $2.2 billion and $1.8 billion , respectively.

Natural gas revenues for the successor second quarter 2017 included recovery of $232 million in cost of natural gas and $12 million in net losses from wholesale gas services. Also included in natural gas revenues were $26 million in additional revenues generated from gas distribution operations as a result of continued investment in infrastructure replacement programs and a $2 million decrease attributable to warmer-than-normal weather, net of hedging.

Natural gas revenues for the predecessor second quarter 2016 reflected recovery of $184 million in cost of natural gas and $95 million in net losses from wholesale gas services, primarily due to mark-to-market losses on storage, transportation, and forward commodity derivatives.

Natural gas revenues for the successor year-to-date 2017 included recovery of $951 million in cost of natural gas and $119 million in net revenues from wholesale gas services. Also included in natural gas revenues was $45 million in additional revenues generated from gas distribution operations as a result of continued investment in infrastructure replacement programs and a $15 million decrease attributable to warmer-than-normal weather, net of hedging.

Natural gas revenues for the predecessor year-to-date 2016 reflected recovery of $755 million in cost of natural gas and $32 million in net losses from wholesale gas services. Also included in natural gas revenues was a $7 million decrease attributable to warmer-than-normal weather, net of hedging.

See "Segment Information" herein for additional information on wholesale gas services' revenues and losses.

Natural gas distribution rates include provisions to adjust billings for fluctuations in natural gas costs. Therefore, recoverable natural gas revenues generally equal the cost of natural gas and do not affect net income from gas distribution operations. See "Cost of Natural Gas" herein for additional information. Revenue impacts from weather and customer growth are described further below.

Heating Season is the period from November through March when natural gas usage and operating revenues are generally higher. Weather typically does not have a significant net income impact during the non-Heating Season. The following table presents the Heating Degree Days information for Illinois and Georgia, the primary locations where Southern Company Gas' operations are impacted by weather.

	Second Quarter			2017 vs. 2016	2017 vs. normal	**Year-to-Date**			2017 vs. 2016	2017 vs. normal
	Normal [a]	**2017**	2016	(warmer)	(warmer)	**Normal** [a]	**2017**	2016	(warmer)	(warmer)
Illinois [b]	**639**	**555**	639	(13)%	(13)%	**3,760**	**3,110**	3,340	(7)%	(17)%
Georgia	**137**	**75**	114	(34)%	(45)%	**1,636**	**1,000**	1,448	(31)%	(39)%

(a) Normal represents the 10-year average from January 1, 2007 through June 30, 2016 for Illinois at Chicago Midway International Airport and for Georgia at Atlanta Hartsfield-Jackson International Airport, based on information obtained from the National Oceanic and Atmospheric Administration, National Climatic Data Center.

(b) The 10-year average Heating Degree Days established by the Illinois Commission in Nicor Gas' 2009 rate case is 617 for the second quarter and 3,519 for the first six months from 1998 through 2007.

For the successor second quarter 2017 and the predecessor second quarter 2016, the weather-related negative pre-tax income impact was limited to $2 million in each period.

Southern Company Gas hedged its exposure to warmer-than-normal weather at Nicor Gas in Illinois; therefore, the weather-related negative pre-tax income impact on gas distribution operations was limited to $5 million ($3 million after tax) and $7 million ($5 million after tax) for the successor year-to-date 2017 and the predecessor year-to-date 2016 , respectively. Southern Company Gas also hedged its exposure at gas marketing services to warmer-than-normal weather in Georgia; therefore, the weather-related negative pre-tax income impact on gas marketing services was limited to $10 million ($6 million after tax) for the successor year-to-date 2017 and there was no impact for the predecessor year-to-date 2016 .

The following table provides the number of customers served by Southern Company Gas at June 30, 2017 and 2016 :

	June 30,		
	2017	2016	**2017 vs. 2016**
	(in thousands, except market share %)		(% change)
Gas distribution operations	**4,573**	4,544	0.6 %
Gas marketing services			
Energy customers (*)	**768**	630	21.9 %
Market share of energy customers in Georgia	**29.1%**	29.3%	
Service contracts	**1,188**	1,197	(0.8)%

(*) Includes approximately 140,000 customers as of June 30, 2017 that were contracted to serve beginning April 1, 2017.

Southern Company Gas anticipates overall customer growth trends at gas distribution operations to continue in 2017 , as it expects continued improvement in the new housing market and low natural gas prices.

Gas marketing services' market share in Georgia decreased slightly at June 30, 2017 compared to June 30, 2016 as a result of a highly competitive marketing environment, which Southern Company Gas expects to continue for the foreseeable future. Southern Company Gas will continue efforts at gas marketing services to enter into targeted markets and expand its energy customers and service contracts.

Cost of Natural Gas

Cost of natural gas was $232 million for the successor second quarter 2017 and $184 million for the predecessor second quarter 2016 , which primarily reflected an increase of 63% in natural gas prices during the successor second quarter 2017 compared to the corresponding period in 2016, partially offset by lower demand for natural gas driven by warmer-than-normal weather.

Cost of natural gas was $951 million for the successor year-to-date 2017 and $755 million for the predecessor year-to-date 2016 , which primarily reflected an increase of 61% in natural gas prices during the successor year-to-date 2017 compared to the corresponding period in 2016, partially offset by lower demand for natural gas driven by warmer-than-normal weather.

Natural gas distribution rates include provisions to adjust billings for fluctuations in natural gas costs. Therefore, recoverable natural gas revenues generally equal the cost of natural gas and do not affect net income from gas distribution operations. For additional information, see MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATIONS – "Cost of Natural Gas" of Southern Company Gas in Item 7 of the Form 10-K and "Natural Gas Revenues" herein.

The following table details the volumes of natural gas sold during all periods presented.

	Second Quarter		2017 vs. 2016	Year-to-Date		2017 vs. 2016
	2017	2016	**% Change**	**2017**	2016	**% Change**
Gas distribution operations *(mmBtu in millions)*						
Firm	**102**	107	(4.7)%	**365**	396	(7.8)%
Interruptible	**23**	22	4.5 %	**48**	49	(2.0)%
Total	**125**	129	(3.1)%	**413**	445	(7.2)%
Gas marketing services *(mmBtu in millions)*						
Firm:						
Georgia	**4**	4	— %	**17**	21	(19.0)%
Illinois	**2**	2	— %	**7**	8	(12.5)%
Other emerging markets	**3**	2	50.0 %	**8**	7	14.3 %
Interruptible:						
Large commercial and industrial	**3**	4	(25.0)%	**7**	8	(12.5)%
Total	**12**	12	— %	**39**	44	(11.4)%
Wholesale gas services *(mmBtu in millions/day)*						
Daily physical sales	**6.2**	7.2	(13.9)%	**6.4**	7.6	(15.8)%

Other Operations and Maintenance Expenses

Other operations and maintenance expenses were $213 million for both the successor second quarter 2017 and the predecessor second quarter 2016 .

Other operations and maintenance expenses were $467 million for the successor year-to-date 2017 and $454 million for the predecessor year-to-date 2016 . Other operations and maintenance expense for the successor year-to-date period reflected increased compensation expenses and pipeline and maintenance expenses, partially offset by low bad debt expense.

Depreciation and Amortization

Depreciation and amortization was $125 million for the successor second quarter 2017 and $104 million for the predecessor second quarter 2016 . The successor second quarter 2017 included $9 million of additional net amortization of intangible assets as a result of fair value adjustments in acquisition accounting at gas midstream operations and gas distribution operations, as well as $7 million in additional depreciation at gas distribution operations due to a $1.1 billion increase in gross property, plant, and equipment since June 30, 2016.

Depreciation and amortization was $244 million for the successor year-to-date 2017 and $206 million for the predecessor year-to-date 2016 . The successor year-to-date 2017 included $19 million of additional net amortization of intangible assets as a result of fair value adjustments in acquisition accounting at gas midstream operations and gas distribution operations, as well as $13 million in additional depreciation at gas distribution operations due to additional assets placed in service.

Taxes Other Than Income Taxes

For the successor second quarter 2017 and the predecessor second quarter 2016 , taxes other than income taxes were $44 million and $37 million , respectively. For the successor year-to-date 2017 and the predecessor year-to-date

2016 , taxes other than income taxes were $114 million and $99 million , respectively. Taxes other than income taxes consist primarily of revenue tax expenses, property taxes, and payroll taxes. Taxes other than income taxes in the successor periods reflected increased revenue-based taxes due to higher revenues at gas distribution operations.

Earnings from Equity Method Investments

For the successor second quarter 2017 , earnings from equity method investments were $29 million , which consisted of $24 million in earnings from SNG and $5 million in earnings from all other investments. For the predecessor second quarter 2016 , earnings from equity method investments were not material.

For the successor year-to-date 2017 , earnings from equity method investments were $68 million , which consisted of $58 million in earnings from SNG and $10 million in earnings from all other investments. For the predecessor year-to-date 2016 , earnings from equity method investments were not material.

See Notes 4 and 11 to the financial statements of Southern Company Gas under "Equity Method Investments – SNG" and "Investment in SNG," respectively, in Item 8 of the Form 10-K and Note (J) to the Condensed Financial Statements under " Southern Company Gas – Equity Method Investments " herein for additional information.

Interest Expense, Net of Amounts Capitalized

For both the successor second quarter 2017 and the predecessor second quarter 2016, interest expense, net of amounts capitalized was $48 million . The successor second quarter 2017 reflects a $10 million reduction resulting from the fair value adjustment of long-term debt in acquisition accounting, partially offset by $6 million of additional interest expense on new debt issuances in 2017 and 2016.

For the successor year-to-date 2017 and the predecessor year-to-date 2016 , interest expense, net of amounts capitalized was $94 million and $96 million , respectively. The successor year-to-date 2017 reflects a $19 million reduction resulting from the fair value adjustment of long-term debt in acquisition accounting, partially offset by $12 million of additional interest expense on new debt issuances in 2017 and 2016.

Income Taxes (Benefit)

For the successor second quarter 2017 and the predecessor second quarter 2016, income taxes (benefit) were $31 million and $(24) million , respectively, driven by pre-tax earnings.

For the successor year-to-date 2017 and the predecessor year-to-date 2016 , income taxes were $180 million and $87 million , respectively, driven by pre-tax earnings and the non-deductibility of certain Merger-related expenses.

Performance and Non-GAAP Measures

Prior to the Merger, Southern Company Gas evaluated segment performance using earnings before interest and taxes (EBIT), which includes operating income, earnings from equity method investments, and other income (expense), net. EBIT excludes interest expense, net of amounts capitalized and income taxes (benefit), which were evaluated on a consolidated basis for those periods. EBIT is used herein to discuss the results of Southern Company Gas' segments for the predecessor period, as EBIT was the primary measure of segment profit or loss for that period. Subsequent to the Merger, Southern Company Gas changed its segment performance measure from EBIT to net income to better align with the performance measure utilized by Southern Company. EBIT for the successor second quarter and year-to-date 2017 presented herein is considered a non-GAAP measure. Southern Company Gas also discusses consolidated EBIT, which is considered a non-GAAP measure for all periods presented. The presentation of consolidated EBIT is believed to provide useful supplemental information regarding a consolidated measure of profit or loss. Southern Company Gas further believes that the presentation of segment EBIT for the successor second quarter and year-to-date 2017 is useful as it allows for a measure of comparability to the other companies with different capital and legal structures, which accordingly may be subject to different interest rates and effective tax rates. The applicable reconciliations of net income to consolidated EBIT and segment EBIT are provided herein.

Adjusted operating margin is a non-GAAP measure that is calculated as operating revenues minus cost of natural gas, cost of other sales, and revenue tax expense. Adjusted operating margin excludes other operations and maintenance expenses, depreciation and amortization, taxes other than income taxes, and Merger-related expenses, which are included in the calculation of operating income as calculated in accordance with GAAP and reflected in the consolidated statements of income. The presentation of adjusted operating margin is believed to provide useful information regarding the contribution resulting from customer growth at gas distribution operations since the cost of natural gas and revenue tax expense can vary significantly and are generally billed directly to customers. Southern Company Gas further believes that utilizing adjusted operating margin at gas marketing services, wholesale gas services, and gas midstream operations allows it to focus on a direct measure of adjusted operating margin before overhead costs. The applicable reconciliation of operating income to adjusted operating margin is provided herein.

EBIT and adjusted operating margin should not be considered alternatives to, or more meaningful indicators of, Southern Company Gas' operating performance than consolidated net income attributable to Southern Company Gas or operating income as determined in accordance with GAAP. In addition, Southern Company Gas' adjusted operating margin may not be comparable to similarly titled measures of other companies.

	Successor	Predecessor	**Successor**	Predecessor
	Second Quarter 2017	Second Quarter 2016	**Year-to-Date 2017**	Year-to-Date 2016
	(in millions)	*(in millions)*	*(in millions)*	*(in millions)*
Operating Income	**$ 96**	$ (27)	**$ 487**	$ 321
Other operating expenses [(a)]	**382**	407	**825**	815
Revenue taxes [(b)]	**(18)**	(17)	**(65)**	(56)
Adjusted Operating Margin	**$ 460**	$ 363	**$ 1,247**	$ 1,080

(a) Includes other operations and maintenance, depreciation and amortization, taxes other than income taxes, and Merger-related expenses.

(b) Nicor Gas' revenue tax expenses, which are passed through directly to customers.

	Successor	Predecessor	**Successor**	Predecessor
	Second Quarter 2017	Second Quarter 2016	**Year-to-Date 2017**	Year-to-Date 2016
	(in millions)	*(in millions)*	*(in millions)*	*(in millions)*
Consolidated Net Income (Loss) Attributable to Southern Company Gas	**$ 49**	$ (51)	**$ 288**	$ 131
Net income attributable to noncontrolling interest [(*)]	**—**	3	**—**	14
Income taxes	**31**	(24)	**180**	87
Interest expense, net of amounts capitalized	**48**	48	**94**	96
EBIT	**$ 128**	$ (24)	**$ 562**	$ 328

(*) See Note 4 to the financial statements of Southern Company Gas under "Variable Interest Entities" in Item 8 of the Form 10-K for additional information.

Segment Information

Adjusted operating margin, operating expenses, and Southern Company Gas' primary performance metric for each segment is illustrated in the tables below. See Note (K) to the Condensed Financial Statements herein for additional information.

	Successor			Predecessor		
	Second Quarter 2017			Second Quarter 2016		
	Adjusted Operating Margin (*)	Operating Expenses (*)	Net Income	Adjusted Operating Margin (*)	Operating Expenses (*)	EBIT
	(in millions)			(in millions)		
Gas distribution operations	$ 409	$ 283	$ 54	$ 386	$ 269	$ 118
Gas marketing services	57	48	4	66	37	29
Wholesale gas services	(13)	14	(17)	(96)	16	(112)
Gas midstream operations	7	13	9	6	12	(5)
All other	3	9	(1)	2	58	(55)
Intercompany eliminations	(3)	(3)	—	(1)	(2)	1
Consolidated	$ 460	$ 364	$ 49	$ 363	$ 390	$ (24)

(*) Operating margin and operating expenses are adjusted for Nicor Gas' revenue tax expenses, which are passed through directly to customers.

	Successor			Predecessor		
	Year-to-Date 2017			Year-to-Date 2016		
	Adjusted Operating Margin (*)	Operating Expenses (*)	Net Income	Adjusted Operating Margin (*)	Operating Expenses (*)	EBIT
	(in millions)			(in millions)		
Gas distribution operations	$ 951	$ 596	$ 171	$ 911	$ 560	$ 353
Gas marketing services	162	101	35	190	81	109
Wholesale gas services	118	29	51	(36)	33	(68)
Gas midstream operations	16	25	25	15	24	(6)
All other	5	14	6	4	65	(60)
Intercompany eliminations	(5)	(5)	—	(4)	(4)	—
Consolidated	$ 1,247	$ 760	$ 288	$ 1,080	$ 759	$ 328

(*) Operating margin and operating expenses are adjusted for Nicor Gas' revenue tax expenses, which are passed through directly to customers.

Gas Distribution Operations

Gas distribution operations is the largest component of Southern Company Gas' business and is subject to regulation and oversight by agencies in each of the states it serves. With the exception of Atlanta Gas Light, Southern Company Gas' second largest utility that operates in a deregulated natural gas market and has a straight-fixed-variable rate design that minimizes the variability of its revenues based on consumption, the earnings of the natural gas distribution utilities can be affected by customer consumption patterns that are a function of weather conditions, price levels for natural gas, and general economic conditions that may impact customers' ability to pay for natural gas consumed. Southern Company Gas has various weather mechanisms, such as weather normalization mechanisms and weather derivative instruments, that limit its exposure to weather changes within typical ranges in its natural gas utilities' service territories.

Successor Second Quarter 2017

Net income of $54 million includes $409 million in adjusted operating margin, $283 million in operating expenses, and $2 million in other income (expense), net, which resulted in EBIT of $128 million . Net income also includes $40 million in interest expense and $34 million in income tax expense. Adjusted operating margin reflects $26 million in additional revenue from the continued investment in infrastructure replacement programs, a base rate increase at Atlanta Gas Light effective March 1, 2017, and a $1 million positive impact of weather, net of hedging, despite warmer-than-normal weather. Operating expenses reflect additional depreciation due to continued investment in infrastructure programs and increased pipeline compliance and maintenance activities.

Predecessor Second Quarter 2016

EBIT of $118 million includes $386 million in adjusted operating margin, $269 million in operating expenses, and $1 million in other income (expense), net. Adjusted operating margin reflects revenue from continued investment in infrastructure replacement programs and increased usage and customer growth, partially offset by a $1 million negative impact of warmer-than-normal weather, net of hedging. Operating expenses reflect depreciation associated with additional assets placed in service.

Successor Year-to-Date 2017

Net income of $171 million includes $951 million in adjusted operating margin, $596 million in operating expenses, and $6 million in other income (expense), net, which resulted in EBIT of $361 million . Net income also includes $80 million in interest expense and $110 million in income tax expense. Adjusted operating margin reflects $45 million in additional revenue from continued investment in infrastructure replacement programs and a base rate increase at Atlanta Gas Light effective March 1, 2017. Also included in adjusted operating margin was increased customer growth, partially offset by a $5 million negative impact of warmer-than-normal weather, net of hedging. Operating expenses reflect a $13 million increase in depreciation associated with additional assets placed in service, as well as increased compensation expense, legal expenses, and pipeline compliance and maintenance activities.

Predecessor Year-to-Date 2016

EBIT of $353 million includes $911 million in adjusted operating margin, $560 million in operating expenses, and $2 million in other income (expense), net. Adjusted operating margin reflects revenue from continued investment in infrastructure replacement programs and increased usage and customer growth, partially offset by a $7 million negative impact of warmer-than-normal weather, net of hedging. Operating expenses reflect depreciation associated with additional assets placed in service.

Gas Marketing Services

Gas marketing services consists of several businesses that provide energy-related products and services to natural gas markets, including warranty sales. Gas marketing services is weather sensitive and uses a variety of hedging strategies, such as weather derivative instruments and other risk management tools, to partially mitigate potential weather impacts. Operating expenses primarily reflect employee costs, marketing, and bad debt expenses.

Successor Second Quarter 2017

Net income of $4 million includes $57 million in adjusted operating margin and $48 million in operating expenses, which resulted in EBIT of $9 million . Net income also includes $2 million in interest expense and $3 million in income tax expense. Adjusted operating margin reflects a $3 million negative impact of warmer-than-normal weather, net of hedging. Operating expenses reflect $10 million in additional amortization of intangible assets due to fair value adjustments to certain assets and liabilities in the application of acquisition accounting.

Predecessor Second Quarter 2016

EBIT of $29 million includes $66 million in adjusted operating margin and $37 million in operating expenses. Adjusted operating margin reflects $7 million in unrealized hedge gains and a $1 million negative impact of

weather, net of hedging. Earnings in the predecessor period include $3 million attributable to noncontrolling interest.

Successor Year-to-Date 2017

Net income of $35 million includes $162 million in adjusted operating margin and $101 million in operating expenses, which resulted in EBIT of $61 million . Net income also includes $3 million in interest expense and $23 million in income tax expense. Adjusted operating margin reflects $2 million of additional revenue as a result of fair value adjustments to certain assets and liabilities in the application of acquisition accounting, as well as a $10 million negative impact of warmer-than-normal weather, net of hedging and $7 million in unrealized hedge losses. Operating expenses also reflect $20 million in additional amortization of intangible assets due to fair value adjustments to certain assets and liabilities in the application of acquisition accounting.

Predecessor Year-to-Date 2016

EBIT of $109 million includes $190 million in adjusted operating margin and $81 million in operating expenses. Adjusted operating margin reflects $9 million in unrealized hedge gains. Earnings in the predecessor period include $14 million attributable to noncontrolling interest.

Wholesale Gas Services

Wholesale gas services is involved in asset management and optimization, storage, transportation, producer and peaking services, natural gas supply, natural gas services, and wholesale gas marketing. Southern Company Gas has positioned the business to generate positive economic earnings on an annual basis even under low volatility market conditions that can result from a number of factors. When market price volatility increases, wholesale gas services is well positioned to capture significant value and generate stronger results. Operating expenses primarily reflect employee compensation and benefits.

Successor Second Quarter 2017

Net loss of $17 million includes $(13) million in adjusted operating margin and $14 million in operating expenses, which resulted in a loss before interest and taxes of $27 million. Also included in net loss is $1 million in interest expense and $11 million in income tax benefit.

Predecessor Second Quarter 2016

Loss before interest and taxes of $112 million includes $(96) million in adjusted operating margin and $16 million in operating expenses.

Successor Year-to-Date 2017

Net income of $51 million includes $118 million in adjusted operating margin and $29 million in operating expenses, which resulted in EBIT of $89 million . Net income also includes $3 million in interest expense and $35 million in income tax expense.

Predecessor Year-to-Date 2016

Loss before interest and taxes of $68 million includes $(36) million in adjusted operating margin, $33 million in operating expenses, and $1 million in other income (expense), net.

The following table illustrates the components of wholesale gas services' adjusted operating margin for the periods presented.

	Successor	Predecessor	Successor	Predecessor
	Second Quarter 2017	Second Quarter 2016	**Year-to-Date 2017**	Year-to-Date 2016
	(in millions)	*(in millions)*	*(in millions)*	*(in millions)*
Commercial activity recognized	**$ (18)**	$ (8)	**$ 69**	$ 34
Gain (loss) on storage derivatives	**17**	(36)	**18**	(38)
Gain (loss) on transportation and forward commodity derivatives	**(2)**	(52)	**37**	(31)
LOCOM adjustments, net of current period recoveries	**(1)**	—	**(1)**	(1)
Impact of purchase accounting adjustments	**(9)**	—	**(5)**	—
Adjusted Operating Margin	**$ (13)**	$ (96)	**$ 118**	$ (36)

Change in Commercial Activity

The commercial activity at wholesale gas services includes recognition of storage and transportation values that were generated in prior periods, which reflect the impact of prior period hedge gains and losses as associated physical transactions occur. Warmer-than-normal weather during the 2016/2017 Heating Season, lower power generation volumes, and build-out of new U.S. pipeline infrastructure, along with increases in natural gas supply, caused low volatility and a tightening of locational or transportation spreads in 2017, negatively impacting the amount of commercial activity revenues generated relative to demand fees for contracted pipeline transportation and storage capacity, and minimum sharing under asset management agreements. However, as natural gas prices and forward storage or time spreads increased, wholesale gas services was able to capture higher storage values that it expects to recognize as commercial activity revenues when natural gas is physically withdrawn from storage. Southern Company Gas anticipates continued low volatility in certain areas of wholesale gas services' portfolio.

Change in Storage and Transportation Derivatives

Volatility in the natural gas market arises from a number of factors, such as weather fluctuations or changes in supply or demand for natural gas in different regions of the U.S. The volatility of natural gas commodity prices has a significant impact on Southern Company Gas' customer rates, long-term competitive position against other energy sources, and the ability of wholesale gas services to capture value from locational and seasonal spreads. In 2017 and 2016 , there was little price volatility; however, the potential exists for market fundamentals indicating some level of increased volatility that would benefit Southern Company Gas' portfolio of pipeline transportation capacity. Additionally, during the first six months of 2017 , forward storage or time spreads applicable to the locations of wholesale gas services' specific storage positions resulted in storage derivative gains. Transportation and forward commodity derivative gains are primarily the result of narrowing transportation basis spreads due to some reduction in supply constraints resulting from new U.S. pipeline infrastructure and increases in natural gas supply and warmer-than-normal weather, which impacted forward prices at natural gas receipt and delivery points, primarily in the Northeast and Midwest regions.

Withdrawal Schedule and Physical Transportation Transactions

The expected natural gas withdrawals from storage and expected offset to prior hedge losses/gains associated with the transportation portfolio of wholesale gas services are presented in the following table, along with the net operating revenues expected at the time of withdrawal from storage and the physical flow of natural gas between contracted transportation receipt and delivery points. Wholesale gas services' expected net operating revenues exclude storage and transportation demand charges, as well as other variable fuel, withdrawal, receipt, and delivery charges, but are net of the estimated impact of profit sharing under its asset management agreements. Further, the amounts that are realizable in future periods are based on the inventory withdrawal schedule, planned physical flow of natural gas between the transportation receipt and delivery points, and forward natural gas prices at June 30,

2017 . A portion of wholesale gas services' storage inventory and transportation capacity is economically hedged with futures contracts, which results in the realization of substantially fixed net operating revenues.

	Storage withdrawal schedule		
	Total storage (WACOG $2.75)	**Expected net operating gains** [a]	**Physical transportation transactions – expected net operating losses** [b]
	(in mmBtu in millions)	*(in millions)*	*(in millions)*
2017	36.5	$ 5	$ (10)
2018 and thereafter	30.9	12	(27)
Total at June 30, 2017	67.4	$ 17	$ (37)

(a) Represents expected operating gains from planned storage withdrawals associated with existing inventory positions and could change as wholesale gas services adjusts its daily injection and withdrawal plans in response to changes in future market conditions and forward NYMEX price fluctuations.

(b) Represents the periods associated with the transportation derivative gains during which the derivatives will be settled and the physical transportation transactions will occur that offset the derivative gains that were previously recognized.

The unrealized storage and transportation derivative gains do not change the underlying economic value of wholesale gas services' storage and transportation positions and will be reversed when the related transactions occur and are recognized. For more information on wholesale gas services' energy marketing and risk management activities, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of Southern Company Gas in Item 7 of the Form 10-K.

Gas Midstream Operations

Gas midstream operations consists primarily of gas pipeline investments, with storage and fuels also aggregated into this segment. Gas pipeline investments consist of the SNG interest, Horizon Pipeline, Atlantic Coast Pipeline, PennEast Pipeline, Dalton Pipeline, and Magnolia Enterprise Holdings, Inc. See Note (J) to the Condensed
Financial Statements herein and Notes 4 and 11 to the financial statements of Southern Company Gas under "Equity
Method Investments – SNG" and "Investment in SNG," respectively, in Item 8 of the Form 10-K for additional
information.

Successor Second Quarter 2017

Net income of $9 million includes $7 million in adjusted operating margin, $13 million in operating expenses, $28 million in earnings from equity method investments, which consists primarily of equity in earnings from the investment in SNG, and $1 million in other income (expense), net, which resulted in EBIT of $23 million . Also included in net income are $8 million in interest expense and $6 million in income tax expense.

Predecessor Second Quarter 2016

Loss before interest and taxes of $5 million includes $6 million in adjusted operating margin, $12 million in operating expenses, and $1 million of other income (expense), net.

Successor Year-to-Date 2017

Net income of $25 million includes $16 million in adjusted operating margin, $25 million in operating expenses, $66 million in earnings from equity method investments, which consists primarily of equity in earnings from the investment in SNG, and $2 million in other income (expense), net, which resulted in EBIT of $59 million . Also included in net income are $17 million in interest expense and $17 million in income tax expense.

Predecessor Year-to-Date 2016

Loss before interest and taxes of $6 million includes $15 million in adjusted operating margin, $24 million in operating expenses, and $3 million of other income (expense), net.

All Other

All other includes Southern Company Gas' investment in Triton, AGL Services Company, and Southern Company Gas Capital, as well as various corporate operating expenses that are not allocated to the reportable segments and interest income (expense) associated with affiliate financing arrangements. There were no Merger-related expenses for the successor second quarter or year-to-date 2017 . For the predecessor second quarter 2016 and year-to-date 2016 , Merger-related expenses included in operating expenses were $53 million and $56 million , respectively.

Segment Reconciliations

Reconciliations of consolidated net income attributable to Southern Company Gas to EBIT for the successor second quarter and year-to-date 2017 , and operating income to adjusted operating margin for all periods presented, are in the following tables. See Note (K) to the Condensed Financial Statements herein for additional information.

	Successor						
	Second Quarter 2017						
	Gas Distribution Operations	Gas Marketing Services	Wholesale Gas Services	Gas Midstream Operations	All Other	Intercompany Elimination	Consolidated
	(in millions)						
Consolidated Net Income	$ 54	$ 4	$ (17)	$ 9	$ (1)	$ —	$ **49**
Income taxes	34	3	(11)	6	(1)	—	**31**
Interest expense, net of amounts capitalized	40	2	1	8	(3)	—	**48**
EBIT	$ 128	$ 9	$ (27)	$ 23	$ (5)	$ —	$ **128**

	Successor						
	Year-to-Date 2017						
	Gas Distribution Operations	Gas Marketing Services	Wholesale Gas Services	Gas Midstream Operations	All Other	Intercompany Elimination	Consolidated
	(in millions)						
Consolidated Net Income	$ 171	$ 35	$ 51	$ 25	$ 6	$ —	$ **288**
Income taxes	110	23	35	17	(5)	—	**180**
Interest expense, net of amounts capitalized	80	3	3	17	(9)	—	**94**
EBIT	$ 361	$ 61	$ 89	$ 59	$ (8)	$ —	$ **562**

	Successor						
	Second Quarter 2017						
	Gas Distribution Operations	Gas Marketing Services	Wholesale Gas Services	Gas Midstream Operations	All Other	Intercompany Elimination	Consolidated
	(in millions)						
Operating Income (Loss)	$ 126	$ 9	$ (27)	$ (6)	$ (6)	$ —	$ **96**
Other operating expenses [(a)]	301	48	14	13	9	(3)	**382**
Revenue tax expense [(b)]	(18)	—	—	—	—	—	**(18)**
Adjusted Operating Margin	$ 409	$ 57	$ (13)	$ 7	$ 3	$ (3)	$ **460**

	Successor						
	Year-to-Date 2017						
	Gas Distribution Operations	**Gas Marketing Services**	**Wholesale Gas Services**	**Gas Midstream Operations**	**All Other**	**Intercompany Elimination**	**Consolidated**
	(in millions)						
Operating Income (Loss)	**$ 355**	**$ 61**	**$ 89**	**$ (9)**	**$ (9)**	**$ —**	**$ 487**
Other operating expenses [(a)]	661	101	29	25	14	(5)	**825**
Revenue tax expense [(b)]	(65)	—	—	—	—	—	**(65)**
Adjusted Operating Margin	**$ 951**	**$ 162**	**$ 118**	**$ 16**	**$ 5**	**$ (5)**	**$ 1,247**

	Predecessor						
	Second Quarter 2016						
	Gas Distribution Operations	Gas Marketing Services	Wholesale Gas Services	Gas Midstream Operations	All Other	Intercompany Elimination	Consolidated
	(in millions)						
Operating Income (Loss)	$ 117	$ 29	$ (112)	$ (6)	$ (56)	$ 1	$ (27)
Other operating expenses [(a)]	286	37	16	12	58	(2)	407
Revenue tax expense [(b)]	(17)	—	—	—	—	—	(17)
Adjusted Operating Margin	$ 386	$ 66	$ (96)	$ 6	$ 2	$ (1)	$ 363

	Predecessor						
	Year-to-Date 2016						
	Gas Distribution Operations	Gas Marketing Services	Wholesale Gas Services	Gas Midstream Operations	All Other	Intercompany Elimination	Consolidated
	(in millions)						
Operating Income (Loss)	$ 351	$ 109	$ (69)	$ (9)	$ (61)	$ —	$ 321
Other operating expenses [(a)]	616	81	33	24	65	(4)	815
Revenue tax expense [(b)]	(56)	—	—	—	—	—	(56)
Adjusted Operating Margin	$ 911	$ 190	$ (36)	$ 15	$ 4	$ (4)	$ 1,080

(a) Includes other operations and maintenance, depreciation and amortization, taxes other than income taxes, and Merger-related expenses.
(b) Nicor Gas' revenue tax expenses, which are passed through directly to customers.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Southern Company Gas' future earnings potential. The level of Southern Company Gas' future earnings depends on numerous factors that affect the opportunities, challenges, and risks of its primary business of natural gas distribution and complementary businesses in the gas marketing services, wholesale gas services, and gas midstream operations sectors. These factors include Southern Company Gas' ability to maintain a constructive regulatory environment that allows for the timely recovery of prudently-incurred costs, the completion and subsequent operation of ongoing infrastructure and other construction projects, creditworthiness of customers, Southern Company Gas' ability to optimize its transportation and storage positions, and its ability to re-contract storage rates at favorable prices. Future earnings in the near term will depend, in part, upon maintaining and growing sales and customers which are subject to a number of factors. These factors include weather, competition, new energy contracts with other utilities, energy conservation practiced

by customers, the use of alternative energy sources by customers, the price of natural gas, the price elasticity of demand, and the rate of economic growth or decline in Southern Company Gas' service territories. Demand for natural gas is primarily driven by economic growth. The pace of economic growth and natural gas demand may be affected by changes in regional and global economic conditions, which may impact future earnings.

Current proposals related to potential federal tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals is dependent on the final form of any legislation enacted and the related transition rules and cannot be determined at this time, but could have a material impact on Southern Company Gas' financial statements.

On July 6, 2017, the State of Illinois enacted tax legislation that increased the effective corporate income tax rate from 5.25% to 7.0% (making the total corporate tax rate 9.5% when combined with the 2.5% personal property replacement tax) effective July 1, 2017. In addition to increasing taxes on future earnings, this legislation will require Southern Company Gas to adjust existing accumulated deferred income tax liabilities to reflect an increased tax rate, and any portion not recoverable through rates will impact earnings. Southern Company Gas is currently evaluating these changes. The ultimate impact of this legislation cannot be determined at this time, but could have a material impact on Southern Company Gas' financial statements.

Volatility of natural gas prices has a significant impact on Southern Company Gas' customer rates, long-term competitive position against other energy sources, and the ability of its gas marketing services and wholesale gas services segments to capture value from locational and seasonal spreads. Additionally, changes in commodity prices subject a significant portion of Southern Company Gas' operations to earnings variability.

Over the longer-term, volatility is expected to be low to moderate and locational and/or transportation spreads are expected to decrease as new pipelines are built to reduce the existing supply constraints in the shale areas of the Northeast U.S. To the extent these pipelines are delayed or not built, volatility could increase. Additional economic factors may contribute to this environment, including a significant drop in oil and natural gas prices, which could lead to consolidation of natural gas producers or reduced levels of natural gas production. Further, if economic conditions continue to improve, including the new housing market, the demand for natural gas may increase, which may cause natural gas prices to rise and drive higher volatility in the natural gas markets on a longer-term basis.

For additional information relating to these issues, see "Risk Factors" of Southern Company Gas in Item 1A of the Form 10-K.

In September 2016, Southern Company Gas acquired a 50% equity interest in SNG. See OVERVIEW – "Merger and Acquisition Activities" and Note (J) to the Condensed Financial Statements herein and Notes 4 and 11 to the financial statements of Southern Company Gas under "Equity Method Investments – SNG" and "Investment in SNG," respectively, in Item 8 of the Form 10-K for additional information. As part of its business strategy, Southern Company Gas regularly considers and evaluates joint development arrangements as well as acquisitions and dispositions of businesses and assets.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis or through market-based contracts. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are completed. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for natural gas, which could negatively affect results of operations, cash flows, and financial condition. See Note (B) under " Environmental Remediation " to the Condensed Financial Statements herein and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company Gas in Item 7 and Note 3 to the financial statements of Southern Company Gas under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

FERC Matters

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters" of Southern Company Gas in Item 7 and Note 4 to the financial statements of Southern Company Gas in Item 8 of the Form 10-K for additional information regarding the Dalton Pipeline project.

On August 1, 2017, the Dalton Pipeline was placed in service as authorized by the FERC and transportation service for customers commenced.

Regulatory Matters

See Note 3 to the financial statements of Southern Company Gas under "Regulatory Matters" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under " Regulatory Matters – Southern Company Gas " herein for additional information regarding Southern Company Gas' regulatory matters.

Riders

Nicor Gas has established a variable tax cost adjustment rider, which was approved by the Illinois Commission effective July 16, 2017. This rider provides for recovery of the invested capital tax imposed on Nicor Gas through an annual true-up and reconciliation mechanism. Accordingly, this rider will not have a significant effect on Southern Company Gas' net income.

Natural Gas Cost Recovery

Southern Company Gas has established natural gas cost recovery rates approved by the relevant state regulatory agencies in the states in which it serves. Natural gas cost recovery revenues are adjusted for differences in actual recoverable natural gas costs and amounts billed in current regulated rates. Changes in the billing factor will not have a significant effect on Southern Company Gas' revenues or net income, but will affect cash flows.

Base Rate Cases

Settled Base Rate Cases

On February 21, 2017, the Georgia PSC approved the Georgia Rate Adjustment Mechanism (GRAM) and a $20 million increase in annual base rate revenues for Atlanta Gas Light, effective March 1, 2017. GRAM adjusts base rates annually, up or down, based on the previously approved ROE of 10.75% and does not collect revenue through special riders and surcharges. Various infrastructure programs previously authorized by the Georgia PSC under Atlanta Gas Light's STRIDE program, which include the Integrated Vintage Plastic Replacement Program, Integrated System Reinforcement Program, and Integrated Customer Growth Program, will continue under GRAM and the recovery of and return on the infrastructure program investments will be included in annual base rate adjustments. The Georgia PSC will review Atlanta Gas Light's performance annually under GRAM.

Beginning with the next rate adjustment in June 2018, Atlanta Gas Light's recovery of the previously unrecovered Pipeline Replacement Program revenue through 2014, as well as the mitigation costs associated with the Pipeline Replacement Program that were not previously included in its rates, will also be included in GRAM. In connection with the GRAM approval, the last monthly Pipeline Replacement Program surcharge increase became effective March 1, 2017.

In September 2016, Elizabethtown Gas filed a general base rate case with the New Jersey BPU requesting a $19 million increase in annual base rate revenues. The requested increase was based on a projected 12-month test year ending March 31, 2017 and a ROE of 10.25%. On June 30, 2017, the New Jersey BPU approved a settlement that provides for a $13 million increase in annual base rate revenues, effective July 1, 2017, based on a ROE of 9.6%. Also included in the settlement was a new composite depreciation rate that is expected to result in a $3 million annual reduction of depreciation.

Pending Base Rate Cases

On March 10, 2017, Nicor Gas filed a general base rate case with the Illinois Commission requesting a $208 million increase in annual base rate revenues. The requested increase is based on a 2018 projected test year and a ROE of 10.7%. The Illinois Commission is expected to rule on the requested increase within the 11-month statutory time limit, after which rate adjustments will be effective.

On March 31, 2017, Virginia Natural Gas filed a general base rate case with the Virginia Commission requesting a $44 million increase in annual base rate revenues. The requested increase is based on a projected 12-month test year beginning September 1, 2017 and a ROE of 10.25%. The requested increase includes $13 million related to the recovery of investments under the Steps to Advance Virginia's Energy (SAVE) program. The Virginia Commission is expected to rule on the requested increase in the first quarter 2018. Rate adjustments are expected to be effective September 1, 2017, subject to refund.

The ultimate outcome of these pending base rate cases cannot be determined at this time.

Regulatory Infrastructure Programs

Southern Company Gas is engaged in various infrastructure programs that update or expand its gas distribution systems to improve reliability and ensure the safety of its utility infrastructure, and recovers in rates its investment and a return associated with these infrastructure programs.

Nicor Gas

In 2014, the Illinois Commission approved Nicor Gas' nine-year regulatory infrastructure program, Investing in Illinois. Under this program, Nicor Gas placed into service $75 million of qualifying assets during the first six months of 2017 .

Atlanta Gas Light

Atlanta Gas Light's STRIDE program, which started in 2009, consists of three individual programs that update and expand gas distribution systems and liquefied natural gas facilities as well as improve system reliability to meet operational flexibility and customer growth. Through the programs under STRIDE, Atlanta Gas Light invested $94 million during the first six months of 2017 .

In August 2016, Atlanta Gas Light filed a petition with the Georgia PSC for approval of a four-year extension of its Integrated System Reinforcement Program (i-SRP) seeking approval to invest an additional $177 million to improve and upgrade its core gas distribution system in years 2017 through 2020.

The recovery of and return on current and future capital investments under the STRIDE program will be included in the annual base rate revenue adjustment under GRAM rather than a separate surcharge. The proposed capital investments associated with the extension of i-SRP were included in the 2017 annual base rate revenue under GRAM that was approved by the Georgia PSC on February 21, 2017. See " Base Rate Cases " herein for additional information.

Elizabethtown Gas

In 2013, the New Jersey BPU approved the extension of Elizabethtown Gas' Aging Infrastructure Replacement program, under which Elizabethtown Gas invested $12 million during the first six months of 2017 .

Virginia Natural Gas

In March 2016, the Virginia Commission approved an extension to the SAVE program, under which Virginia Natural Gas invested $14 million during the first six months of 2017 .

Florida City Gas

The Florida PSC approved Florida City Gas' Safety, Access, and Facility Enhancement program in 2015. Under the program, Florida City Gas invested $7 million during the first six months of 2017 .

Other Matters

Southern Company Gas is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Southern Company Gas is subject to certain claims and legal actions arising in the ordinary course of business. The ultimate outcome of such pending or potential litigation against Southern Company Gas cannot be predicted at this time; however, for current proceedings not specifically reported in Note (B) to the Condensed Financial Statements herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Company Gas' financial statements. See Note (B) to the Condensed Financial Statements herein for a discussion of various other contingencies and regulatory matters, and other matters being litigated which may affect future earnings potential.

Nicor Gas and Nicor Energy Services Company, wholly-owned subsidiaries of Southern Company Gas, and Nicor Inc. were defendants in a putative class action initially filed in 2011 in the state court in Cook County, Illinois. The plaintiffs purported to represent a class of the customers who purchased the Gas Line Comfort Guard product from Nicor Energy Services Company and variously alleged that the marketing, sale, and billing of the Gas Line Comfort Guard product violated the Illinois Consumer Fraud and Deceptive Business Practices Act, constituting common law fraud and resulting in unjust enrichment of these entities. The plaintiffs sought, on behalf of the classes they purported to represent, actual and punitive damages, interest, costs, attorney fees, and injunctive relief. On February 8, 2017, the judge denied the plaintiffs' motion for class certification and Southern Company Gas' motion for summary judgment. On March 7, 2017, the parties reached a settlement, which was finalized and effective on April 3, 2017. The settlement did not have a material impact on Southern Company Gas' financial statements.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Southern Company Gas prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Southern Company Gas in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Southern Company Gas' results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Southern Company Gas in Item 7 of the Form 10-K for a complete discussion of Southern Company Gas' critical accounting policies and estimates related to Utility Regulation, Pushdown of Acquisition Accounting, Assessment of Assets, Derivatives and Hedging Activities, Pension and Other Postretirement Benefits, and Contingent Obligations.

Recently Issued Accounting Standards

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 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.

While Southern Company Gas expect s most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of all revenue arrangements. The majority of Southern Company Gas' revenue, including energy provided to customers, is from tariff offerings that provide natural gas without a defined contractual term, as well as longer-term contractual agreements , including non-derivative natural gas asset management and optimization arrangements . Southern Company Gas expect s that the revenue from contracts with these customers will not result in a significant shift in the timing of revenue recognition for such sales .

Southern Company Gas' ongoing evaluation of other revenue streams and related contracts includes unregulated sales to customers. Some revenue arrangements, such as energy-related derivatives and alternative revenue programs, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed or presented separately from revenues under ASC 606 on Southern Company Gas' financial statements. In addition, the power

and utilities industry continues to evaluate other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). Although final implementation guidance has not been issued, Southern Company Gas expect s CIAC to be out of the scope of ASC 606.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. Southern Company Gas intend s to use the modified retrospective method of adoption effective January 1, 2018. Southern Company Gas has also elected to utilize practical expedients which allow 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, disclosures will include comparative information on 2018 financial statement line items under current guidance. While the adoption of ASC 606, including the cumulative-effect adjustment, is not expected to have a material impact on either the timing or amount of revenues recognized in Southern Company Gas' financial statements, Southern Company Gas will continue to evaluate the requirements, as well as any additional clarifying guidance that may be issued.

On January 26, 2017, the FASB issued ASU No. 2017-04, *Intangibles – Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment* (ASU 2017-04). ASU 2017-04 removes the requirement to compare the implied fair value of goodwill with the carrying amount as part of Step 2 of the goodwill impairment test. Under the new standard, the goodwill impairment loss will be measured as the excess of a reporting unit's carrying amount over its fair value, not exceeding the total amount of goodwill allocated to that reporting unit, which may increase the frequency of goodwill impairment charges if a future goodwill impairment test does not pass the Step 1 evaluation. ASU 2017-04 is effective prospectively for annual and interim periods beginning on or after December 15, 2019, and early adoption is permitted on testing dates after January 1, 2017.

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 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 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 annual periods beginning after December 15, 2017, including interim periods within those annual periods. Southern Company Gas is currently evaluating the new standard. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in Southern Company Gas' 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 adoption of ASU 2017-07 is not expected to have a material impact on Southern Company Gas' financial statements.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Overview" of Southern Company Gas in Item 7 of the Form 10-K for additional information. As a result of the Merger that closed on July 1, 2016, the results reported herein include disclosure of the successor second quarter and year-to-date 2017 and the predecessor second quarter and year-to-date 2016. See OVERVIEW – " Merger and Acquisition Activities " and Note (I) to the Condensed Financial Statements under "Southern Company – Merger with Southern Company Gas" herein for additional information.

Southern Company Gas' financial condition remained stable at June 30, 2017 . Southern Company Gas intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit agreements to meet future capital and liquidity needs. See " Capital Requirements and Contractual Obligations ," " Sources of Capital ," and " Financing Activities " herein for additional information.

By regulation, Nicor Gas is restricted, to the extent of its retained earnings balance, in the amount it can dividend or loan to affiliates and is not permitted to make money pool loans to affiliates. Due to the increased working capital requirements associated with Nicor Gas' Investing in Illinois infrastructure replacement program, since 2015, Nicor Gas has temporarily ceased distributing dividends to Southern Company Gas. Elizabethtown Gas is restricted by its dividend policy as established by the New Jersey BPU in the amount it can dividend to its parent company to the extent of 70% of its quarterly net income. Additionally, as stipulated in the New Jersey BPU's order approving the Merger, Southern Company Gas is prohibited from paying dividends to its parent company, Southern Company, if Southern Company Gas' senior unsecured debt rating falls below investment grade. As of June 30, 2017 , the amount of subsidiary retained earnings and net income available to dividend totaled $739 million . These restrictions did not have any impact on Southern Company Gas' ability to meet its cash obligations, nor does management expect such restrictions to materially impact Southern Company Gas' ability to meet its currently anticipated cash obligations.

Net cash provided from operating activities totaled $1.2 billion for the successor first six months of 2017 and $1.1 billion for the predecessor first six months of 2016 . These cash flows were primarily driven by the sale of natural gas inventory during the respective periods.

Net cash used for investing activities totaled $781 million for the successor first six months of 2017 , primarily due to gross property additions related to capital expenditures for infrastructure replacement programs at gas distribution operations and capital contributed to equity method investments in pipelines. Net cash used for investing activities totaled $559 million for the predecessor first six months of 2016 , primarily due to gross property additions related to capital expenditures for infrastructure replacement programs at gas distribution operations.

Net cash used for financing activities totaled $351 million for the successor first six months of 2017 , primarily due to net repayments of commercial paper borrowings and common stock dividend payments to Southern Company, partially offset by proceeds from debt issuances and capital contributions from Southern Company. Net cash used for financing activities totaled $558 million for the predecessor first six months of 2016 , primarily due to net repayments of commercial paper borrowings, the redemption of long-term debt, and common stock dividend payments to shareholders, partially offset by proceeds from debt issuances . Cash flows from financing activities vary from period to period based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes at June 30, 2017 include an increase of $514 million in total property, plant, and equipment primarily due to capital expenditures for infrastructure replacement programs, an increase in long-term debt of $418 million primarily due to $450 million of senior notes issued in May 2017, and decreases of $223 million in natural gas for sale, including temporary LIFO liquidation due to the use of natural gas stored during the first six months of 2017 , and $631 million in notes payable related primarily to net repayments of commercial paper borrowings at Nicor Gas. Other significant balance sheet changes include decreases of $141 million and $63 million in energy marketing receivables and payables, respectively, due to lower natural gas prices.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company Gas in Item 7 of the Form 10-K for a description of Southern Company Gas' capital requirements for its infrastructure programs, scheduled maturities of long-term debt and the related interest, as well as pipeline charges, storage capacity, and gas supply, operating leases, asset management agreements, standby letters of credit and performance/surety bonds, financial derivative obligations, pension and other postretirement benefit plans, and other purchase commitments, primarily related to environmental remediation liabilities. Approximately $22 million will be required through June 30, 2018 to fund maturities of long-term debt. See " Sources of Capital " herein for additional information.

The regulatory infrastructure programs and other construction programs are subject to periodic review and revision, and actual costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in FERC rules and regulations; state regulatory approvals; changes in legislation; the cost and efficiency of labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 to the consolidated financial statements of Southern Company Gas in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements herein for information regarding additional factors that may impact infrastructure investment expenditures.

Sources of Capital

Southern Company Gas plans to obtain the funds to meet its future capital needs through operating cash flows, short-term debt borrowings under its commercial paper programs, external securities issuances, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, depend upon regulatory approval, prevailing market conditions, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Southern Company Gas in Item 7 of the Form 10-K for additional information.

At June 30, 2017 , Southern Company Gas' current liabilities exceeded current assets by $572 million primarily as a result of $626 million in notes payable. Southern Company Gas' current liabilities frequently exceed current assets because of commercial paper borrowings used to fund daily operations, scheduled maturities of long-term debt, and significant seasonal fluctuations in cash needs. Southern Company Gas intends to utilize operating cash flows, commercial paper, and debt securities issuances, as market conditions permit, as well as equity contributions from Southern Company to fund its short-term capital needs. Southern Company Gas has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet liquidity needs.

At June 30, 2017 , Southern Company Gas had approximately $38 million of cash and cash equivalents. Committed credit arrangements with banks at June 30, 2017 were as follows:

Company	Expires 2022	Unused
	(in millions)	
Southern Company Gas Capital	$ 1,200	$ 1,149
Nicor Gas	700	700
Total	$ 1,900	$ 1,849

Additionally, Pivotal Utility Holdings is party to a series of loan agreements with the New Jersey Economic Development Authority and Brevard County, Florida under which five series of gas facility revenue bonds totaling $200 million have been issued.

See Note 6 to the consolidated financial statements of Southern Company Gas under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under " Bank Credit Arrangements " herein for additional information.

As reflected in the table above, in May 2017, Southern Company Gas Capital and Nicor Gas terminated their existing credit arrangements for $1.3 billion and $700 million, respectively, which were to mature in 2017 and 2018, and entered into a new multi-year credit arrangement (Facility) currently allocated for $1.2 billion and $700 million, respectively, with a maturity date of 2022.

The Facility included in the table above contains a covenant that limits the ratio of debt to capitalization (as defined in each facility) to a maximum of 70% for each of Southern Company Gas and Nicor Gas and contains a cross-acceleration provision to other indebtedness (including guarantee obligations) of the applicable company. Such cross-acceleration provision to other indebtedness would trigger an event of default of the applicable company if Southern Company Gas or Nicor Gas defaulted on indebtedness, the payment of which was then accelerated. At

June 30, 2017 , each of the applicable companies was in compliance with such covenant. The Facility does not contain a material adverse change clause at the time of borrowings.

Subject to applicable market conditions, the applicable company expects to renew or replace the Facility as needed, prior to expiration. In connection therewith, the applicable company may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

Southern Company Gas makes short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. Commercial paper borrowings are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Short-term Debt at June 30, 2017		Short-term Debt During the Period (*)		
	Amount Outstanding	**Weighted Average Interest Rate**	**Average Amount Outstanding**	**Weighted Average Interest Rate**	**Maximum Amount Outstanding**
Commercial paper:	*(in millions)*		*(in millions)*		*(in millions)*
Southern Company Gas Capital	$ 581	1.5%	$ 558	1.3%	$ 750
Nicor Gas	45	1.4	143	1.2	308
Short-term loans:					
Southern Company Gas	—	—	—	4.0	40
Total	$ 626	1.5%	$ 701	1.3%	

(*) Average and maximum amounts are based upon daily balances during the successor three-month period ended June 30, 2017 .

Southern Company Gas believes the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and operating cash flows.

Credit Rating Risk

Southern Company Gas does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change below BBB- and/or Baa3. These contracts are for physical gas purchases and sales and energy price risk management. The maximum potential collateral requirements under these contracts at June 30, 2017 were $9 million .

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of Southern Company Gas 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 Southern Company Gas, Southern Company Gas Capital, and Nicor Gas) from stable to negative.

Financing Activities

The long-term debt on Southern Company Gas' consolidated balance sheets includes both principal and non-principal components. As of June 30, 2017 , the non-principal components totaled $537 million , which consisted of the unamortized portions of the fair value adjustment recorded in purchase accounting, debt premiums, debt discounts, and debt issuance costs.

In May 2017, Southern Company Gas Capital issued $450 million aggregate principal amount of Series 2017A 4.40% Senior Notes due May 30, 2047. The proceeds were used to repay Southern Company Gas' short-term indebtedness and for general corporate purposes.

Subsequent to June 30, 2017, Atlanta Gas Light Company repaid at maturity $22 million of Series C medium-term notes.

Subsequent to June 30, 2017, Nicor Gas agreed to issue $400 million aggregate principal amount of First Mortgage Bonds in a private placement, $200 million of which is expected to be issued in each of August 2017 and November 2017.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Southern Company Gas 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.

Market Price Risk

Other than the items discussed below, there were no material changes to Southern Company Gas' disclosures about market price risk during the successor second quarter and year-to-date 2017. For an in-depth discussion of Southern Company Gas' market price risks, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of Southern Company Gas in Item 7 of the Form 10-K. Also see Notes (C) and (H) to the Condensed Financial Statements herein for information relating to derivative instruments.

Southern Company Gas is exposed to market risks, primarily commodity price risk, interest rate risk, and weather risk. Due to various cost recovery mechanisms, the natural gas distribution utilities of Southern Company Gas that sell natural gas directly to end-use customers have limited exposure to market volatility of natural gas prices. Certain natural gas distribution utilities of Southern Company Gas manage fuel-hedging programs implemented per the guidelines of their respective state regulatory agencies to hedge the impact of market fluctuations in natural gas prices for customers. For the weather risk associated with Nicor Gas, Southern Company Gas has a corporate weather hedging program that utilizes weather derivatives to reduce the risk of lower operating margins potentially resulting from significantly warmer-than-normal weather. In addition, certain non-regulated operations routinely utilize various types of derivative instruments to economically hedge certain commodity price and weather risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and over-the-counter energy contracts, such as forward contracts, futures contracts, options contracts, and swap agreements. Some of these economic hedge activities may not qualify, or are not designated, for hedge accounting treatment. The following table illustrates the change in the net fair value of Southern Company Gas' derivative instruments during all periods presented, and provides details of the net fair value of contracts outstanding as of the dates presented.

	Successor	Predecessor	**Successor**	Predecessor
	Second Quarter 2017	Second Quarter 2016	**Year-to-Date 2017**	Year-to-Date 2016
	(in millions)	*(in millions)*	*(in millions)*	*(in millions)*
Contracts outstanding at beginning of period, assets (liabilities), net	**$ 64**	$ (44)	**$ 12**	$ 75
Contracts realized or otherwise settled	**(20)**	8	**(16)**	(77)
Current period changes [(a)]	**7**	(48)	**55**	(82)
Contracts outstanding at the end of period, assets (liabilities), net	**51**	(84)	**51**	(84)
Netting of cash collateral	**71**	120	**71**	120
Cash collateral and net fair value of contracts outstanding at end of period [(b)]	**$ 122**	$ 36	**$ 122**	$ 36

(a) Current period changes also include the fair value of new contracts entered into during the period, if any.

(b) Net fair value of derivative instruments outstanding includes premiums and the intrinsic values associated with weather derivatives of $11 million at June 30, 2017 and $5 million at June 30, 2016 .

The maturities of Southern Company Gas' energy-related derivative contracts at June 30, 2017 were as follows:

		Fair Value Measurements Successor – June 30, 2017		
		Maturity		
	Total Fair Value	Year 1	Years 2 & 3	Years 4 and thereafter
	(in millions)			
Level 1 [(a)]	$ (12)	$ 5	$ (14)	$ (3)
Level 2 [(b)]	63	27	30	6
Fair value of contracts outstanding at end of period [(c)]	$ 51	$ 32	$ 16	$ 3

(a) Valued using NYMEX futures prices.

(b) Valued using basis transactions that represent the cost to transport natural gas from a NYMEX delivery point to the contract delivery point. These transactions are based on quotes obtained either through electronic trading platforms or directly from brokers.

(c) Excludes cash collateral of $71 million at June 30, 2017 .

NOTES TO THE CONDENSED FINANCIAL STATEMENTS
FOR
THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
ALABAMA POWER COMPANY
GEORGIA POWER COMPANY
GULF POWER COMPANY
MISSISSIPPI POWER COMPANY
SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
SOUTHERN COMPANY GAS AND SUBSIDIARY COMPANIES
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INDEX TO APPLICABLE NOTES TO FINANCIAL STATEMENTS BY REGISTRANT

The following unaudited notes to the condensed financial statements are a combined presentation. The list below indicates the registrants to which each footnote applies.

Registrant	Applicable Notes
Southern Company	A, B, C, D, E, F, G, H, I, J, K
Alabama Power	A, B, C, E, F, G, H
Georgia Power	A, B, C, E, F, G, H
Gulf Power	A, B, C, E, F, G, H
Mississippi Power	A, B, C, E, F, G, H
Southern Power	A, B, C, D, E, G, H, I
Southern Company Gas	A, B, C, E, F, G, H, I, J, K

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
ALABAMA POWER COMPANY
GEORGIA POWER COMPANY
GULF POWER COMPANY
MISSISSIPPI POWER COMPANY
SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
SOUTHERN COMPANY GAS AND SUBSIDIARY COMPANIES

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (UNAUDITED)

(A) INTRODUCTION

The condensed quarterly financial statements of each registrant included herein have been prepared by such registrant, without audit, pursuant to the rules and regulations of the SEC. The Condensed Balance Sheets as of December 31, 2016 have been derived from the audited financial statements of each registrant. In the opinion of each registrant's management, the information regarding such registrant furnished herein reflects all adjustments, which, except as otherwise disclosed, are of a normal recurring nature, necessary to present fairly the results of operations for the periods ended June 30, 2017 and 2016 . Certain information and footnote disclosures normally included in annual financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations, although each registrant believes that the disclosures regarding such registrant are adequate to make the information presented not misleading. Disclosures which would substantially duplicate the disclosures in the Form 10-K and details which have not changed significantly in amount or composition since the filing of the Form 10-K are generally omitted from this Quarterly Report on Form 10-Q unless specifically required by GAAP. Therefore, these Condensed Financial Statements should be read in conjunction with the financial statements and the notes thereto included in the Form 10-K. Due to the seasonal variations in the demand for energy, operating results for the periods presented are not necessarily indicative of the operating results to be expected for the full year.

Southern Company's financial statements reflect its investments in its subsidiaries, including Southern Company Gas as a result of the Merger, on a consolidated basis. Southern Company Gas' results of operations and cash flows for the three and six months ended June 30, 2017 and financial condition as of June 30, 2017 and December 31, 2016 are reflected within Southern Company's consolidated amounts in these accompanying notes herein. The equity method is used for entities in which Southern Company has significant influence but does not control, including Southern Company Gas' investment in SNG, and for variable interest entities where Southern Company has an equity investment but is not the primary beneficiary. See Note (I) under " Southern Company – Merger with Southern Company Gas " for additional information regarding the Merger.

Pursuant to the Merger, Southern Company pushed down the application of the acquisition method of accounting to the consolidated financial statements of Southern Company Gas such that the assets and liabilities are recorded at their respective fair values, and goodwill has been established for the excess of the purchase price over the fair value of net identifiable assets. Accordingly, the consolidated financial statements of Southern Company Gas for periods before and after July 1, 2016 (acquisition date) reflect different bases of accounting, and the financial positions and results of operations of those periods are not comparable. Throughout Southern Company Gas' condensed consolidated financial statements and the accompanying notes herein, periods prior to July 1, 2016 are identified as "predecessor," while periods after the acquisition date are identified as "successor."

Certain prior year data presented in the financial statements have been reclassified to conform to the current year presentation. These reclassifications had no impact on the results of operations, financial position, or cash flows of any registrant.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

Recently Issued Accounting Standards

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 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.

While the registrants expect most of their revenue to be included in the scope of ASC 606, they have not fully completed the evaluation of all revenue arrangements. The majority of Southern Company's, the traditional electric operating companies', and Southern Company Gas' revenue, including energy provided to customers, is from tariff offerings that provide electricity or natural gas without a defined contractual term, as well as longer-term contractual commitments , including PPAs and non-derivative natural gas asset management and optimization arrangements . The majority of Southern Power's revenues includes longer-term PPAs for generation capacity and energy. The registrants expect the adoption of ASC 606 will not result in a significant shift from the current timing of revenue recognition for such transactions .

The registrants' ongoing evaluation of other revenue streams and related contracts includes unregulated sales to customers. Some revenue arrangements, such as certain PPAs , energy-related derivatives , and alternative revenue programs, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed or presented separately from revenues under ASC 606 on the registrants' financial statements. In addition, the power and utilities industry continues to evaluate other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). Although final implementation guidance has not been issued, Southern Company, the traditional electric operating companies, and Southern Company Gas expect CIAC to be out of the scope of ASC 606.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. The registrants intend to use the modified retrospective method of adoption effective January 1, 2018. The registrants have also elected to utilize practical expedients which allow them 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, disclosures will include comparative information on 2018 financial statement line items under current guidance. While the adoption of ASC 606, including the cumulative-effect adjustment, is not expected to have a material impact on either the timing or amount of revenues recognized in the registrants' financial statements, the registrants will continue to evaluate the requirements, as well as any additional clarifying guidance that may be issued.

On January 26, 2017, the FASB issued ASU No. 2017-04, *Intangibles – Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment* (ASU 2017-04). ASU 2017-04 removes the requirement to compare the implied fair value of goodwill with the carrying amount as part of Step 2 of the goodwill impairment test. Under the new standard, the goodwill impairment loss will be measured as the excess of a reporting unit's carrying amount over its fair value, not exceeding the total amount of goodwill allocated to that reporting unit, which may increase the frequency of goodwill impairment charges if a future goodwill impairment test does not pass the Step 1 evaluation. ASU 2017-04 is effective prospectively for annual and interim periods beginning on or after December 15, 2019, and early adoption is permitted on testing dates after January 1, 2017.

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 income from operations. Additionally, only the service cost component is eligible for capitalization, when applicable. However, all cost components remain eligible

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

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 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 annual periods beginning after December 15, 2017, including interim periods within those annual periods. Southern Company, the traditional electric operating companies, and Southern Company Gas are currently evaluating the new standard. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in Southern Company's , the traditional electric operating companies', and Southern Company Gas' 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 adoption of ASU 2017-07 is not expected to have a material impact on Southern Company's , the traditional electric operating companies', or Southern Company Gas' financial statements.

Affiliate Transactions

Prior to the completion of Southern Company Gas' acquisition of its 50% equity interest in SNG, SCS (as agent for Alabama Power, Georgia Power, and Southern Power) and Southern Company Gas had entered into long-term interstate natural gas transportation agreements with SNG. The interstate transportation service provided to Alabama Power, Georgia Power, Southern Power, and Southern Company Gas by SNG pursuant to these agreements is governed by the terms and conditions of SNG's natural gas tariff and is subject to FERC regulation. For the six months ended June 30, 2017 , transportation costs under these agreements for Alabama Power, Georgia Power, Southern Power, and Southern Company Gas were approximately $4 million , $51 million , $13 million , and $16 million , respectively.

SCS, as agent for Georgia Power and Southern Power, has agreements with certain subsidiaries of Southern Company Gas to purchase natural gas. For the six months ended June 30, 2017 , natural gas purchases made by Georgia Power and Southern Power from Southern Company Gas' subsidiaries were approximately $9 million and $56 million , respectively.

Goodwill and Other Intangible Assets

At June 30, 2017 and December 31, 2016, goodwill was as follows:

	Goodwill	
	At June 30, 2017	At December 31, 2016
	(in millions)	
Southern Company	$ 6,271	$ 6,251
Southern Power	$ 2	$ 2
Southern Company Gas		
Gas distribution operations	$ 4,702	$ 4,702
Gas marketing services	1,265	1,265
Southern Company Gas total	$ 5,967	$ 5,967

Goodwill is not amortized, but is subject to an annual impairment test during the fourth quarter of each year, or more frequently if impairment indicators arise.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

Other intangible assets were as follows:

	At June 30, 2017			At December 31, 2016		
	Gross Carrying Amount	Accumulated Amortization	Other Intangible Assets, Net	Gross Carrying Amount	Accumulated Amortization	Other Intangible Assets, Net
		(in millions)			*(in millions)*	
Southern Company						
Other intangible assets subject to amortization:						
Customer relationships	$ 288	$ (57)	$ 231	$ 268	$ (32)	$ 236
Trade names	159	(11)	148	158	(5)	153
Patents	4	—	4	4	—	4
Backlog	5	(1)	4	5	(1)	4
Storage and transportation contracts	64	(21)	43	64	(2)	62
Software and other	4	(1)	3	2	—	2
PPA fair value adjustments	456	(35)	421	456	(22)	434
Total other intangible assets subject to amortization	$ 980	$ (126)	$ 854	$ 957	$ (62)	$ 895
Other intangible assets not subject to amortization:						
Federal Communications Commission licenses	$ 75	$ —	$ 75	$ 75	$ —	$ 75
Total other intangible assets	$ 1,055	$ (126)	$ 929	$ 1,032	$ (62)	$ 970
Southern Power						
Other intangible assets subject to amortization:						
PPA fair value adjustments	$ 456	$ (35)	$ 421	$ 456	$ (22)	$ 434
Southern Company Gas						
Other intangible assets subject to amortization:						
Gas marketing services						
Customer relationships	$ 221	$ (53)	$ 168	$ 221	$ (30)	$ 191
Trade names	115	(6)	109	115	(2)	113
Wholesale gas services						
Storage and transportation contracts	64	(21)	43	64	(2)	62
Total other intangible assets subject to amortization	$ 400	$ (80)	$ 320	$ 400	$ (34)	$ 366

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

Amortization associated with other intangible assets was as follows:

	Three Months Ended	Six Months Ended
	June 30, 2017	
	(in millions)	
Southern Company	$ 29	$ 65
Southern Power	$ 6	$ 13
Southern Company Gas	$ 20	$ 46

See Note 12 to the financial statements of Southern Company under "Southern Power" and Note 2 to the financial statements of Southern Power in Item 8 of the Form 10-K for additional information regarding Southern Power's PPA fair value adjustments related to its business acquisitions. Also see Note (I) under " Southern Company – Acquisition of PowerSecure " and " – Merger with Southern Company Gas " for additional information.

Property Damage Reserve

See Note 1 to the financial statements of Gulf Power under "Property Damage Reserve" in Item 8 of the Form 10-K for additional information.

Gulf Power's cost of repairing damages from major storms and other uninsured property damages, including uninsured damages to transmission and distribution facilities, generation facilities, and other property is charged to Gulf Power's property damage reserve. In accordance with a settlement agreement approved by the Florida PSC on April 4, 2017 (2017 Rate Case Settlement Agreement), Gulf Power suspended further property damage reserve accruals effective April 2017. Gulf Power may make discretionary accruals, but is required to resume accruals of $3.5 million annually if the reserve balance falls below zero . In addition, Gulf Power may initiate a storm surcharge to recover costs associated with any tropical systems named by the National Hurricane Center or other catastrophic storm events that reduce the property damage reserve in the aggregate by approximately $31 million (75% of the April 1, 2017 balance) or more. The storm surcharge would begin, on an interim basis, 60 days following the filing of a cost recovery petition, would be limited to $4.00 /month for a 1,000 KWH residential customer unless Gulf Power incurs in excess of $100 million in qualified storm recovery costs in a calendar year, and would replenish the storm reserve to approximately $40 million . See Note (B) under " Regulatory Matters – Gulf Power – Retail Base Rate Cases " for additional details regarding the 2017 Rate Case Settlement Agreement.

Natural Gas for Sale

Southern Company Gas' natural gas distribution utilities, with the exception of Nicor Gas, carry natural gas inventory on a WACOG basis.

Nicor Gas' natural gas inventory is carried at cost on a LIFO basis. Inventory decrements occurring during the year that are restored prior to year end are charged to cost of natural gas at the estimated annual replacement cost. Inventory decrements that are not restored prior to year end are charged to cost of natural gas at the actual LIFO cost of the inventory layers liquidated. Southern Company Gas' inventory decrement at June 30, 2017 is expected to be restored prior to year end. The cost of natural gas, including inventory costs, is recovered from customers under a purchased gas recovery mechanism adjusted for differences between actual costs and amounts billed; therefore, LIFO liquidations have no impact on Southern Company's or Southern Company Gas' net income.

Natural gas inventories for Southern Company Gas' non-utility businesses are carried at the lower of weighted average cost or current market price, with cost determined on a WACOG basis. For any declines in market prices below the WACOG considered to be other than temporary, an adjustment is recorded to reduce the value of natural gas inventories to market value. Southern Company Gas had no material LOCOM adjustment in any period presented.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

(B) CONTINGENCIES AND REGULATORY MATTERS

See Note 3 to the financial statements of the registrants in Item 8 of the Form 10-K for information relating to various lawsuits, other contingencies, and regulatory matters.

General Litigation Matters

Each registrant is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the business activities of Southern Company's subsidiaries are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation against each registrant and any subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on such registrant's financial statements.

Southern Company

On January 20, 2017, a purported securities class action complaint was filed against Southern Company, certain of its officers, and certain former Mississippi Power officers in the U.S. District Court for the Northern District of Georgia, Atlanta Division, by Monroe County Employees' Retirement System on behalf of all persons who purchased shares of Southern Company's common stock between April 25, 2012 and October 29, 2013. The complaint alleges that Southern Company, certain of its officers, and certain former Mississippi Power officers made materially false and misleading statements regarding the Kemper IGCC in violation of certain provisions under the Securities Exchange Act of 1934, as amended. The complaint seeks, among other things, compensatory damages and litigation costs and attorneys' fees. On June 12, 2017, the plaintiffs filed an amended complaint that provided additional detail about their claims, increased the purported class period by one day, and added certain other former Mississippi Power officers as defendants. On July 27, 2017, the defendants filed a motion to dismiss the plaintiffs' amended complaint with prejudice.

On February 27, 2017, Jean Vineyard filed a shareholder derivative lawsuit in the U.S. District Court for the Northern District of Georgia that names as defendants Southern Company, certain of its directors, certain of its officers, and certain former Mississippi Power officers. The complaint alleges that the defendants caused Southern Company to make false or misleading statements regarding the Kemper IGCC cost and schedule. Further, the complaint alleges that the defendants were unjustly enriched and caused the waste of corporate assets. The plaintiff seeks to recover, on behalf of Southern Company, unspecified actual damages and, on her own behalf, attorneys' fees and costs in bringing the lawsuit. The plaintiff also seeks certain changes to Southern Company's corporate governance and internal processes. On March 27, 2017, the court deferred this lawsuit until 30 days after certain further action in the purported securities class action complaint discussed above.

On May 15, 2017, Helen E. Piper Survivor's Trust filed a shareholder derivative lawsuit in the Superior Court of Gwinnett County, State of Georgia, that names as defendants Southern Company, certain of its directors, certain of its officers, and certain former Mississippi Power officers. The complaint alleges that the individual defendants, among other things, breached their fiduciary duties in connection with schedule delays and cost overruns associated with the construction of the Kemper IGCC. The complaint further alleges that the individual defendants authorized or failed to correct false and misleading statements regarding the Kemper IGCC schedule and cost and failed to implement necessary internal controls to prevent harm to Southern Company. The plaintiff seeks to recover, on behalf of Southern Company, unspecified actual damages and disgorgement of profits and, on its behalf, attorneys'

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

fees and costs in bringing the lawsuit. The plaintiff also seeks certain unspecified changes to Southern Company's corporate governance and internal processes.

On June 1, 2017, Judy Mesirov filed a shareholder derivative lawsuit in the U.S. District Court for the Northern District of Georgia, that names as defendants Southern Company, certain of its current and former directors, certain of its officers, and certain former Mississippi Power officers. The complaint alleges that the individual defendants, among other things, breached their fiduciary duties in connection with schedule delays and cost overruns associated with the construction of the Kemper IGCC. The complaint further alleges that the individual defendants authorized or failed to correct false and misleading statements regarding the Kemper IGCC schedule and cost and failed to implement necessary internal controls to prevent harm to Southern Company. The plaintiff seeks to recover, on behalf of Southern Company, unspecified actual damages, disgorgement of profits, and equitable relief and, on her own behalf, attorneys' fees and costs in bringing the lawsuit. The plaintiff also seeks certain unspecified changes to Southern Company's corporate governance and internal processes.

Southern Company believes these legal challenges have no merit; however, an adverse outcome in any of these proceedings could have an impact on Southern Company's results of operations, financial condition, and liquidity. Southern Company will vigorously defend itself in these matters, the ultimate outcome of which cannot be determined at this time.

Georgia Power

In 2011, plaintiffs filed a putative class action against Georgia Power in the Superior Court of Fulton County, Georgia alleging that Georgia Power's collection in rates of municipal franchise fees (all of which are remitted to municipalities) exceeded the amounts allowed in orders of the Georgia PSC and alleging certain state tort law claims. In November 2016, the Georgia Court of Appeals reversed the trial court's previous dismissal of the case and remanded the case to the trial court for further proceedings. Georgia Power has filed a petition for writ of certiorari with the Georgia Supreme Court. Georgia Power believes the plaintiffs' claims have no merit and intends to vigorously defend itself in this matter. The ultimate outcome of this matter cannot be determined at this time.

Southern Power

During 2015, Southern Power indirectly acquired a 51% membership interest in RE Roserock LLC (Roserock), the owner of the Roserock facility in Pecos County, Texas, which was under construction by Recurrent Energy, LLC and was subsequently placed in service in November 2016. Prior to placing the facility in service, certain solar panels were damaged during installation. While the facility currently is generating energy consistent with operational expectations and PPA obligations, Southern Power is pursuing remedies under its insurance policies and other contracts to repair or replace these solar panels. In connection therewith, Southern Power is withholding payments of approximately $26 million from the construction contractor, who has placed a lien on the Roserock facility for the same amount. The amounts withheld are included in other accounts and notes payable and other current liabilities on Southern Company's consolidated balance sheets and other accounts payable and other current liabilities on Southern Power's consolidated balance sheets. On May 18, 2017, Roserock filed a lawsuit in the state district court in Pecos County, Texas, against X.L. America, Inc. (XL) and North American Elite Insurance Company (North American Elite) seeking recovery from an insurance policy for damages resulting from a hail storm and certain installation practices by the construction contractor, McCarthy Building Companies, Inc. (McCarthy). On May 19, 2017, Roserock filed a separate lawsuit against McCarthy in the state district court in Travis County, Texas alleging breach of contract and breach of warranty for the damages sustained at the Roserock facility, which has since been moved to the U.S. District Court for the Western District of Texas. On May 22, 2017, McCarthy filed a lawsuit against Roserock, Array Technologies, Inc., Canadian Solar (USA), Inc., XL, and North American Elite in the U.S. District Court for the Western District of Texas alleging, among other things, breach of contract, and requesting foreclosure of mechanic's liens against Roserock. On July 18, 2017, the U.S. District Court for the Western District of Texas consolidated the two pending lawsuits. Southern Power intends to vigorously pursue and defend these matters, the ultimate outcome of which cannot be determined at this time.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
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Southern Company Gas

Nicor Gas and Nicor Energy Services Company, wholly-owned subsidiaries of Southern Company Gas, and Nicor Inc. were defendants in a putative class action initially filed in 2011 in the state court in Cook County, Illinois. The plaintiffs purported to represent a class of the customers who purchased the Gas Line Comfort Guard product from Nicor Energy Services Company and variously alleged that the marketing, sale, and billing of the Gas Line Comfort Guard product violated the Illinois Consumer Fraud and Deceptive Business Practices Act, constituting common law fraud and resulting in unjust enrichment of these entities. The plaintiffs sought, on behalf of the classes they purported to represent, actual and punitive damages, interest, costs, attorney fees, and injunctive relief. On February 8, 2017, the judge denied the plaintiffs' motion for class certification and Southern Company Gas' motion for summary judgment. On March 7, 2017, the parties reached a settlement, which was finalized and effective on April 3, 2017. The settlement did not have a material impact on Southern Company's or Southern Company Gas' financial statements.

Environmental Remediation

The Southern Company system must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Southern Company system could incur substantial costs to clean up affected sites. The traditional electric operating companies and the natural gas distribution utilities in Illinois, New Jersey, Georgia, and Florida have each received authority from their respective state PSCs or other applicable state regulatory agencies to recover approved environmental compliance costs through regulatory mechanisms. These regulatory mechanisms are adjusted annually or as necessary within limits approved by the state PSCs or other applicable state regulatory agencies.

Georgia Power's environmental remediation liability was $12 million and $17 million as of June 30, 2017 and December 31, 2016, respectively. Georgia Power has been designated or identified as a potentially responsible party at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act, and assessment and potential cleanup of such sites is expected.

Gulf Power's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $51 million and $44 million as of June 30, 2017 and December 31, 2016, respectively. These estimated costs primarily relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at Gulf Power's substations. The schedule for completion of the remediation projects is subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through Gulf Power's environmental cost recovery clause; therefore, these liabilities have no impact on net income.

Southern Company Gas' environmental remediation liability was $416 million and $426 million as of June 30, 2017 and December 31, 2016, respectively, based on the estimated cost of environmental investigation and remediation associated with known current and former manufactured gas plant operating sites. These environmental remediation expenditures are recoverable from customers through rate mechanisms approved by the applicable state regulatory agencies of the natural gas distribution utilities, with the exception of one site representing $5 million of the total accrued remediation costs.

The final outcome of these matters cannot be determined at this time. However, the final disposition of these matters is not expected to have a material impact on the financial statements of Southern Company, Georgia Power, Gulf Power, or Southern Company Gas.

FERC Matters

Municipal and Rural Associations Tariff

See Note 3 to the financial statements of Mississippi Power under "FERC Matters" in Item 8 of the Form 10-K for additional information regarding a settlement agreement entered into by Mississippi Power regarding the

establishment of a regulatory asset for Kemper IGCC-related costs. See " Integrated Coal Gasification Combined Cycle " herein for information regarding the Kemper IGCC.

In March 2016, Mississippi Power reached a settlement agreement with its wholesale customers, which was subsequently approved by the FERC, for an increase in wholesale base revenues under the MRA cost-based electric tariff, primarily as a result of placing scrubbers for Plant Daniel Units 1 and 2 in service in 2015. The settlement agreement became effective for services rendered beginning May 1, 2016, resulting in an estimated annual revenue increase of $7 million under the MRA cost-based electric tariff. Additionally, under the settlement agreement, the tariff customers agreed to similar regulatory treatment for MRA tariff ratemaking as the treatment approved for retail ratemaking through an order issued by the Mississippi PSC in December 2015 (In-Service Asset Rate Order). This regulatory treatment primarily includes (i) recovery of the Kemper IGCC assets currently operational and providing service to customers and other related costs, (ii) amortization of the Kemper IGCC-related regulatory assets included in rates under the settlement agreement over the 36 months ending April 30, 2019, (iii) Kemper IGCC-related expenses included in rates under the settlement agreement no longer being deferred and charged to expense, and (iv) removing all of the Kemper IGCC CWIP from rate base with a corresponding increase in accrual of AFUDC. The additional resulting AFUDC totaled approximately $22 million through the suspension of Kemper IGCC start-up activities.

See " Integrated Coal Gasification Combined Cycle " herein for additional information.

Fuel Cost Recovery

Mississippi Power has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. At June 30, 2017 , the amount of over-recovered wholesale MRA fuel costs included in the balance sheets was $7 million compared to $13 million at December 31, 2016 . Over-recovered wholesale MB fuel costs included in the balance sheets were immaterial at June 30, 2017 and December 31, 2016 .

See Note 3 to the financial statements of Mississippi Power under "FERC Matters – Fuel Cost Recovery" in Item 8 of the Form 10-K for additional information.

Market-Based Rate Authority

See Note 3 to the financial statements of Southern Company and Mississippi Power under "FERC Matters – Market-Based Rate Authority" and Note 3 to the financial statements of Alabama Power, Georgia Power, Gulf Power, and Southern Power under "FERC Matters" in Item 8 of the Form 10-K for additional information regarding the traditional electric operating companies' and Southern Power's market power proceeding and amendment to their market-rate tariff.

On May 17, 2017, the FERC accepted the traditional electric operating companies' and Southern Power's compliance filing accepting the terms of the FERC's February 2, 2017 order regarding an amendment by the traditional electric operating companies and Southern Power to their market-based rate tariff. While the FERC's order references the traditional electric operating companies' and Southern Power's market power proceeding, it remains a separate, ongoing matter.

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Regulatory Matters

Alabama Power

See Note 3 to the financial statements of Southern Company and Alabama Power under "Regulatory Matters – Alabama Power" and "Retail Regulatory Matters," respectively, in Item 8 of the Form 10-K for additional information regarding Alabama Power's recovery of retail costs through various regulatory clauses and accounting orders. The balance of each regulatory clause recovery on the balance sheet follows:

Regulatory Clause	Balance Sheet Line Item	June 30, 2017	December 31, 2016
		(in millions)	
Rate CNP Compliance [(*)]	Deferred under recovered regulatory clause revenues	$ 6	$ 9
Rate CNP PPA	Over recovered regulatory clause revenues	1	—
	Deferred under recovered regulatory clause revenues	—	142
Retail Energy Cost Recovery	Other regulatory liabilities, current	11	76
Natural Disaster Reserve	Other regulatory liabilities, deferred	56	69

(*) In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, Alabama Power reclassified $36 million of its under recovered balance for Rate CNP Compliance to a deferred regulatory asset account.

Georgia Power

Rate Plans

See Note 3 to the financial statements of Southern Company and Georgia Power under "Regulatory Matters – Georgia Power – Rate Plans" and "Retail Regulatory Matters – Rate Plans," respectively, in Item 8 of the Form 10-K for additional information.

Georgia Power's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Georgia PSC. Georgia Power currently recovers its costs from the regulated retail business through the 2013 ARP, which includes traditional base tariff rates, Demand-Side Management tariffs, Environmental Compliance Cost Recovery tariffs, and Municipal Franchise Fee tariffs. In addition, financing costs related to the construction of Plant Vogtle Units 3 and 4 are being collected through the NCCR tariff and fuel costs are collected through a separate fuel cost recovery tariff. See " Nuclear Construction " herein and Note 3 to the financial statements of Southern Company under "Regulatory Matters – Georgia Power – Nuclear Construction" and Georgia Power under "Retail Regulatory Matters – Nuclear Construction" in Item 8 of the Form 10-K for additional information regarding the NCCR tariff. Also see " Fuel Cost Recovery " herein and Note 3 to the financial statements of Southern Company under "Regulatory Matters – Georgia Power – Fuel Cost Recovery" and Georgia Power under "Retail Regulatory Matters – Fuel Cost Recovery" in Item 8 of the Form 10-K for additional information regarding fuel cost recovery.

Integrated Resource Plan

See Note 3 to the financial statements of Southern Company and Georgia Power under "Regulatory Matters – Georgia Power – Integrated Resource Plan" and "Retail Regulatory Matters – Integrated Resource Plan," respectively, in Item 8 of the Form 10-K for additional information regarding Georgia Power's triennial Integrated Resource Plan.

On March 7, 2017, the Georgia PSC approved Georgia Power's decision to suspend work at a future generation site in Stewart County, Georgia, due to changing economics, including load forecasts and lower fuel costs. The timing

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of recovery for costs incurred of approximately $50 million will be determined by the Georgia PSC in a future base rate case. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

See Note 3 to the financial statements of Southern Company and Georgia Power under "Regulatory Matters – Georgia Power – Fuel Cost Recovery" and "Retail Regulatory Matters – Fuel Cost Recovery," respectively, in Item 8 of the Form 10-K for additional information.

As of June 30, 2017 , Georgia Power's under recovered fuel balance totaled $61 million and is included in other deferred charges and assets on Southern Company's and Georgia Power's condensed balance sheets. As of December 31, 2016 , Georgia Power's over recovered fuel balance totaled $84 million and is included in other current liabilities on Southern Company's and Georgia Power's condensed balance sheets.

Fuel cost recovery revenues are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's or Georgia Power's revenues or net income, but will affect cash flow.

Nuclear Construction

See Note 3 to the financial statements of Southern Company and Georgia Power under "Regulatory Matters – Georgia Power – Nuclear Construction" and "Retail Regulatory Matters – Nuclear Construction," respectively, in Item 8 of the Form 10-K for additional information regarding Georgia Power's construction of Plant Vogtle Units 3 and 4, Vogtle Construction Monitoring (VCM) reports, the NCCR tariff, and the Contractor Settlement Agreement.

Vogtle 3 and 4 Agreement and EPC Contractor Bankruptcy

In 2008, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into the Vogtle 3 and 4 Agreement, pursuant to which the EPC Contractor agreed to design, engineer, procure, construct, and test Plant Vogtle Units 3 and 4. Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Georgia Power's proportionate share of Plant Vogtle Units 3 and 4 is 45.7% .

The Vogtle 3 and 4 Agreement also provided for liquidated damages upon the EPC Contractor's failure to fulfill the schedule and certain performance guarantees, each subject to an aggregate cap of 10% of the contract price, or approximately $920 million (approximately $420 million based on Georgia Power's ownership interest). Under the Toshiba Guarantee, Toshiba guaranteed certain payment obligations of the EPC Contractor, including any liability of the EPC Contractor for abandonment of work. In January 2016, Westinghouse delivered to the Vogtle Owners $920 million of letters of credit from financial institutions (Westinghouse Letters of Credit) to secure a portion of the EPC Contractor's potential obligations under the Vogtle 3 and 4 Agreement. The Westinghouse Letters of Credit are subject to annual renewals through June 30, 2020 and require 60 days' written notice to Georgia Power in the event the Westinghouse Letters of Credit will not be renewed.

Under the terms of the Vogtle 3 and 4 Agreement, the EPC Contractor did not have the right to terminate the Vogtle 3 and 4 Agreement for convenience. In the event of an abandonment of work by the EPC Contractor, the maximum liability of the EPC Contractor under the Vogtle 3 and 4 Agreement was 40% of the contract price (approximately $1.7 billion based on Georgia Power's ownership interest).

On March 29, 2017, the EPC Contractor filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. To provide for a continuation of work at Plant Vogtle Units 3 and 4, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into an interim assessment agreement with the EPC Contractor (Interim Assessment Agreement), which the bankruptcy court approved on March 30, 2017.

The Interim Assessment Agreement provided, among other items, that during the term of the Interim Assessment Agreement (i) Georgia Power was obligated to pay, on behalf of the Vogtle Owners, all costs accrued by the EPC

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
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Contractor for subcontractors and vendors for services performed or goods provided, with these amounts paid to the EPC Contractor, except that amounts accrued for Fluor Corporation (Fluor) were paid directly to Fluor; (ii) the EPC Contractor provided certain engineering, procurement, and management services for Plant Vogtle Units 3 and 4, to the same extent as contemplated by the Vogtle 3 and 4 Agreement, and Georgia Power, on behalf of the Vogtle Owners, made payments of $5.4 million per week for these services; (iii) Georgia Power had the right to make payments, on behalf of the Vogtle Owners, directly to subcontractors and vendors who had accounts past due with the EPC Contractor; (iv) the EPC Contractor used commercially reasonable efforts to provide information reasonably requested by Georgia Power as was necessary to continue construction and investigation of the completion status of Plant Vogtle Units 3 and 4; (v) the EPC Contractor rejected or accepted the Vogtle 3 and 4 Agreement by the termination of the Interim Assessment Agreement; and (vi) Georgia Power did not exercise any remedies against Toshiba under the Toshiba Guarantee. Under the Interim Assessment Agreement, all parties expressly reserved all rights and remedies under the Vogtle 3 and 4 Agreement and all related security and collateral under applicable law.

The Interim Assessment Agreement, as amended, expired on July 27, 2017. Georgia Power's aggregate liability for the Vogtle Owners under the Interim Assessment Agreement totaled approximately $650 million , of which $552 million had been paid or accrued as of June 30, 2017. Georgia Power's proportionate share of this aggregate liability totaled approximately $297 million .

Subsequent to the EPC Contractor bankruptcy filing, a number of subcontractors to the EPC Contractor, including Fluor Enterprises, Inc., a subsidiary of Fluor, alleged non-payment by the EPC Contractor for amounts owed for work performed on Plant Vogtle Units 3 and 4. Georgia Power, acting for itself and as agent for the Vogtle Owners, has taken, and continues to take, actions to remove liens filed by these subcontractors through the posting of surety bonds. Georgia Power estimates the aggregate liability, through July 31, 2017, of the Vogtle Owners for the removal of subcontractor liens and payment of other EPC Contractor pre-petition accounts payable to total approximately $400 million , of which $354 million had been paid or accrued as of June 30, 2017. Georgia Power's proportionate share of this aggregate liability totaled approximately $183 million .

On June 9, 2017, Georgia Power and the other Vogtle Owners and Toshiba entered into a settlement agreement regarding the Toshiba Guarantee (Guarantee Settlement Agreement). Pursuant to the Guarantee Settlement Agreement, Toshiba acknowledged the amount of its obligation under the Toshiba Guarantee is $3.68 billion (Guarantee Obligations), of which Georgia Power's proportionate share is approximately $1.7 billion , and that the Guarantee Obligations exist regardless of whether Plant Vogtle Units 3 and 4 are completed. The Guarantee Settlement Agreement also provides for a schedule of payments for the Guarantee Obligations, beginning in October 2017 and continuing through January 2021. In the event Toshiba receives certain payments, including sale proceeds, from or related to Westinghouse (or its subsidiaries) or Toshiba Nuclear Energy Holdings (UK) Limited (or its subsidiaries), it will hold a portion of such payments in trust for the Vogtle Owners and promptly pay them as offsets against any remaining Guarantee Obligations. Under the Guarantee Settlement Agreement, the Vogtle Owners will forbear from exercising certain remedies, including drawing on the Westinghouse Letters of Credit, until June 30, 2020, unless certain events of nonpayment, insolvency, or other material breach of the Guarantee Settlement Agreement by Toshiba occur. If such an event occurs, the balance of the Guarantee Obligations will become immediately due and payable, and the Vogtle Owners may exercise any and all rights and remedies, including drawing on the Westinghouse Letters of Credit without restriction. In addition, the Guarantee Settlement Agreement does not restrict the Vogtle Owners from fully drawing on the Westinghouse Letters of Credit in the event they are not renewed or replaced prior to the expiration date.

On June 23, 2017, Toshiba released a revised outlook for fiscal year 2016, which reflected a negative shareholders' equity balance of approximately $5 billion as of March 31, 2017, and announced that its independent audit process was continuing. Toshiba has also announced the existence of material events and conditions that raise substantial doubt about Toshiba's ability to continue as a going concern. As a result, substantial risk regarding the Vogtle Owners' ability to fully collect the Guarantee Obligations continues to exist. An inability or other failure by Toshiba to perform its obligations under the Guarantee Settlement Agreement could have a further material impact on the net

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
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cost to the Vogtle Owners to complete construction of Plant Vogtle Units 3 and 4 and, therefore, on Southern Company's and Georgia Power's financial statements.

Additionally, on June 9, 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the EPC Contractor entered into a services agreement (Services Agreement), which was amended and restated on July 20, 2017, for the EPC Contractor to transition construction management of Plant Vogtle Units 3 and 4 to Southern Nuclear and to provide ongoing design, engineering, and procurement services to Southern Nuclear. On July 20, 2017, the bankruptcy court approved the EPC Contractor's motion seeking authorization to (i) enter into the Services Agreement, (ii) assume and assign to the Vogtle Owners certain project-related contracts, (iii) join the Vogtle Owners as counterparties to certain assumed project-related contracts, and (iv) reject the Vogtle 3 and 4 Agreement. The Services Agreement, and the EPC Contractor's rejection of the Vogtle 3 and 4 Agreement, became effective upon approval by the DOE on July 27, 2017. The Services Agreement will continue until the start-up and testing of Plant Vogtle Units 3 and 4 is complete and electricity is generated and sold from both units. The Services Agreement is terminable by the Vogtle Owners upon 30 days' written notice.

The ultimate outcome of these matters cannot be determined at this time.

Regulatory Matters

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4 with a certified capital cost of $4.418 billion . In addition, in 2009 the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows Georgia Power to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff by including the related CWIP accounts in rate base during the construction period. As of June 30, 2017 , Georgia Power had recovered approximately $1.4 billion of financing costs.

On December 20, 2016, the Georgia PSC voted to approve a settlement agreement (Vogtle Cost Settlement Agreement) resolving the following prudence matters: (i) none of the $3.3 billion of costs incurred through December 31, 2015 and reflected in the fourteenth VCM report will be disallowed from rate base on the basis of imprudence; (ii) the Contractor Settlement Agreement is reasonable and prudent and none of the amounts paid or to be paid pursuant to the Contractor Settlement Agreement should be disallowed from rate base on the basis of imprudence; (iii) financing costs on verified and approved capital costs will be deemed prudent provided they are incurred prior to December 31, 2019 and December 31, 2020 for Plant Vogtle Units 3 and 4, respectively; and (iv) (a) the in-service capital cost forecast will be adjusted to $5.680 billion (Revised Forecast), which includes a contingency of $240 million above Georgia Power's then current forecast of $5.440 billion , (b) capital costs incurred up to the Revised Forecast will be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, and (c) Georgia Power would have the burden to show that any capital costs above the Revised Forecast are reasonable and prudent. Under the terms of the Vogtle Cost Settlement Agreement, the certified in-service capital cost for purposes of calculating the NCCR tariff will remain at $4.418 billion . Construction capital costs above $4.418 billion will accrue AFUDC through the date each unit is placed in service. The ROE used to calculate the NCCR tariff was reduced from 10.95% (the ROE rate setting point authorized by the Georgia PSC in the 2013 ARP) to 10.00% effective January 1, 2016. For purposes of the AFUDC calculation, the ROE on costs between $4.418 billion and $5.440 billion will also be 10.00% and the ROE on any amounts above $5.440 billion would be Georgia Power's average cost of long-term debt. If the Georgia PSC adjusts Georgia Power's ROE rate setting point in a rate case prior to Plant Vogtle Units 3 and 4 being placed into retail rate base, then the ROE for purposes of calculating both the NCCR tariff and AFUDC will likewise be 95 basis points lower than the revised ROE rate setting point. If Plant Vogtle Units 3 and 4 are not placed in service by December 31, 2020, then (i) the ROE for purposes of calculating the NCCR tariff will be reduced an additional 300 basis points, or $8 million per month, and may, at the Georgia PSC's discretion, be accrued to be used for the benefit of customers, until such time as the units are placed in service and (ii) the ROE used to calculate AFUDC will be Georgia Power's average cost of long-term debt.

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Under the terms of the Vogtle Cost Settlement Agreement, the Georgia PSC will determine, for retail ratemaking purposes, the process of transitioning Plant Vogtle Units 3 and 4 from a construction project to an operating plant no later than Georgia Power's base rate case required to be filed by July 1, 2019.

The Georgia PSC has approved fifteen VCM reports covering the periods through June 30, 2016, including construction capital costs incurred, which through that date totaled $3.7 billion . Georgia Power filed its sixteenth VCM report, covering the period from July 1 through December 31, 2016, requesting approval of $222 million of construction capital costs incurred during that period, with the Georgia PSC on February 27, 2017.

The ultimate outcome of these matters cannot be determined at this time.

Revised Cost and Schedule

Georgia Power and the other Vogtle Owners are continuing to conduct comprehensive schedule and cost-to-complete assessments, as well as cancellation cost assessments, to determine the impact of the EPC Contractor's bankruptcy filing on the construction cost and schedule for Plant Vogtle Units 3 and 4. Georgia Power's preliminary assessment results indicate that its proportionate share of the remaining estimated cost to complete Plant Vogtle Units 3 and 4 ranges as follows:

Preliminary in-service dates					
Unit 3		February 2021	–		March 2022
Unit 4		February 2022	–		March 2023
			(in billions)		
Preliminary estimated cost to complete	$	3.9	–	$	4.6
CWIP as of June 30, 2017		4.5			4.5
Guarantee Obligations		(1.7)			(1.7)
Estimated capital costs	**$**	**6.7**	**–**	**$**	**7.4**
Vogtle Cost Settlement Agreement Revised Forecast		(5.7)			(5.7)
Estimated net additional capital costs	**$**	**1.0**	**–**	**$**	**1.7**

Georgia Power's estimates for cost to complete and schedule are based on preliminary analysis and remain subject to further refinement of labor productivity and consumable and commodity quantities and costs.

Georgia Power's estimated financing costs during the construction period total approximately $3.1 billion to $3.5 billion , of which approximately $1.4 billion had been incurred through June 30, 2017.

Georgia Power's preliminary cancellation cost estimate results indicate that its proportionate share of the estimated cancellation costs is approximately $400 million . As a result, as of June 30, 2017, total estimated costs subject to evaluation by Georgia Power and the Georgia PSC in the event of a cancellation decision are as follows:

		Preliminary Cancellation Cost Estimate
		(in billions)
CWIP as of June 30, 2017	$	4.5
Financing costs collected, net of tax		1.4
Cancellation costs (*)		0.4
Total	**$**	**6.3**

(*) The estimate for cancellation costs includes, but is not limited to, costs to terminate contracts for construction and other services, as well as costs to secure the Plant Vogtle Units 3 and 4 construction site.

The Guarantee Obligations continue to exist in the event of cancellation. In addition, under Georgia law, prudently incurred costs related to certificated projects cancelled by the Georgia PSC are allowed recovery, including carrying

costs, in future retail rates. Georgia Power will continue working with the Georgia PSC and the other Vogtle Owners to determine future actions related to Plant Vogtle Units 3 and 4, including, but not limited to, the status of construction and rate recovery, and currently expects to include its recommendation in its seventeenth VCM report to be filed with the Georgia PSC in late August 2017.

The ultimate outcome of these matters is dependent on the completion of the assessments described above, as well as the related regulatory treatment, and cannot be determined at this time.

Other Matters

As of June 30, 2017 , Georgia Power had borrowed $2.6 billion related to Plant Vogtle Units 3 and 4 costs through a loan guarantee agreement between Georgia Power and the DOE and a multi-advance credit facility among Georgia Power, the DOE, and the FFB. See Note 6 to the financial statements of Southern Company and Georgia Power under "DOE Loan Guarantee Borrowings" in Item 8 of the Form 10-K and Note (E) under " DOE Loan Guarantee Borrowings " for additional information, including applicable covenants, events of default, mandatory prepayment events, and conditions to borrowing.

The IRS has allocated PTCs to Plant Vogtle Units 3 and 4 which require that the applicable unit be placed in service prior to 2021. The net present value of Georgia Power's PTCs is estimated at approximately $400 million per unit.

There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4 at the federal and state level and additional challenges may arise if construction proceeds. Processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance matters, including the timely resolution of Inspections, Tests, Analyses, and Acceptance Criteria and the related approvals by the NRC, may arise if construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs.

If construction continues, the risk remains that challenges with labor productivity, fabrication, delivery, assembly, and installation of plant systems, structures, and components, or other issues could arise and may further impact project schedule and cost.

The ultimate outcome of these matters cannot be determined at this time.

Gulf Power

See Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters" in Item 8 of the Form 10-K for additional information regarding Gulf Power's rates and charges for service to retail customers.

Retail Base Rate Cases

See Note 3 to the financial statements of Southern Company and Gulf Power under "Regulatory Matters – Gulf Power – Retail Base Rate Cases" and "Retail Regulatory Matters – Retail Base Rate Cases," respectively, in Item 8 of the Form 10-K for additional information.

In 2013, the Florida PSC approved a settlement agreement (2013 Rate Case Settlement Agreement) that authorized Gulf Power to reduce depreciation and record a regulatory asset up to $62.5 million from January 2014 through June 2017. In any given month, such depreciation reduction could not exceed the amount necessary for the retail ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized retail ROE range then in effect. For 2014 and 2015, Gulf Power recognized reductions in depreciation of $8.4 million and $20.1 million , respectively. No net reduction in depreciation was recorded in 2016. In the first six months of 2017 , Gulf Power recognized the remaining allowable reductions in depreciation totaling $34.0 million .

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On April 4, 2017, the Florida PSC approved the 2017 Rate Case Settlement Agreement among Gulf Power and three intervenors with respect to Gulf Power's request to increase retail base rates. Under the terms of the 2017 Rate Case Settlement Agreement, Gulf Power increased rates effective with the first billing cycle in July 2017 to provide an annual overall net customer impact of approximately $54.3 million . The net customer impact consists of a $62.0 million increase in annual base revenues less an annual equivalent credit of approximately $7.7 million for 2017 for certain wholesale revenues to be provided through December 2019 through the purchased power capacity cost recovery clause. In addition, Gulf Power continued its authorized retail ROE midpoint (10.25%) and range (9.25% to 11.25%), is deemed to have an equity ratio of 52.5% for all retail regulatory purposes, and implemented new dismantlement accruals effective July 1, 2017. Gulf Power will also begin amortizing the regulatory asset associated with the investment balances remaining after the retirement of Plant Smith Units 1 and 2 (357 MWs) over 15 years effective January 1, 2018 and will implement new depreciation rates effective January 1, 2018. The 2017 Rate Case Settlement Agreement also resulted in a $32.5 million write-down of Gulf Power's ownership of Plant Scherer Unit 3 (205 MWs), which was recorded in the first quarter 2017. The remaining issues related to the inclusion of Gulf Power's investment in Plant Scherer Unit 3 in retail rates have been resolved as a result of the 2017 Rate Case Settlement Agreement, including recoverability of certain costs associated with the ongoing ownership and operation of the unit through the environmental cost recovery clause rate approved by the Florida PSC in November 2016.

Cost Recovery Clauses

See Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Cost Recovery Clauses" in Item 8 of the Form 10-K for additional information regarding Gulf Power's recovery of retail costs through various regulatory clauses and accounting orders. Gulf Power has four regulatory clauses which are approved by the Florida PSC. The balance of each regulatory clause recovery on the balance sheet follows:

Regulatory Clause	**Balance Sheet Line Item**	**June 30, 2017**	December 31, 2016
		(in millions)	
Fuel Cost Recovery	Under recovered regulatory clause revenues	**$ 7**	$ —
Fuel Cost Recovery	Other regulatory liabilities, current	**—**	15
Purchased Power Capacity Recovery	Under recovered regulatory clause revenues	**5**	—
Environmental Cost Recovery	Under recovered regulatory clause revenues	**12**	13
Energy Conservation Cost Recovery	Under recovered regulatory clause revenues	**2**	4

As discussed previously, the 2017 Rate Case Settlement Agreement resolved the remaining issues related to Gulf Power's inclusion of certain costs associated with the ongoing ownership and operation of Plant Scherer Unit 3 in the environmental cost recovery clause and no adjustment to the environmental cost recovery clause rate approved by the Florida PSC in November 2016 was made.

Mississippi Power

Performance Evaluation Plan

See Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Performance Evaluation Plan" in Item 8 of the Form 10-K for additional information regarding Mississippi Power's base rates.

On March 15, 2017, Mississippi Power submitted its annual PEP lookback filing for 2016, which reflected the need for a $5 million surcharge to be recovered from customers. The filing has been suspended for review by the Mississippi PSC. The ultimate outcome of this matter cannot be determined at this time.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
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Energy Efficiency

See Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Energy Efficiency" in Item 8 of the Form 10-K for additional information regarding Mississippi Power's energy efficiency programs.

On July 6, 2017, the Mississippi PSC issued an order approving Mississippi Power's Energy Efficiency Cost Rider compliance filing, which increased annual retail revenues by approximately $2 million effective with the first billing cycle for August 2017.

Environmental Compliance Overview Plan

On May 4, 2017, the Mississippi PSC approved Mississippi Power's ECO Plan filing for 2017, which requested the maximum 2% annual increase in revenues, approximately $18 million , primarily related to the Plant Daniel Units 1 and 2 scrubbers placed in service in 2015. The rates became effective with the first billing cycle for June 2017. Approximately $26 million of related revenue requirements in excess of the 2% maximum was deferred for inclusion in the 2018 filing.

Fuel Cost Recovery

See Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Fuel Cost Recovery" in Item 8 of the Form 10-K for additional information regarding Mississippi Power's retail fuel cost recovery.

At June 30, 2017 , the amount of over-recovered retail fuel costs included on Mississippi Power's condensed balance sheet was $14 million compared to $37 million at December 31, 2016 .

Ad Valorem Tax Adjustment

See Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Ad Valorem Tax Adjustment" in Item 8 of the Form 10-K for additional information regarding Mississippi Power's ad valorem tax adjustments.

On July 6, 2017, the Mississippi PSC approved Mississippi Power's annual ad valorem tax adjustment factor filing for 2017, which included an annual rate increase of 0.85% , or $8 million in annual retail revenues, primarily due to increased assessments.

Southern Company Gas

Natural Gas Cost Recovery

Southern Company Gas has established natural gas cost recovery rates approved by the relevant state regulatory agencies in the states in which it serves. Natural gas cost recovery revenues are adjusted for differences in actual recoverable natural gas costs and amounts billed in current regulated rates. Changes in the billing factor will not have a significant effect on Southern Company's or Southern Company Gas' revenues or net income, but will affect cash flows.

Base Rate Cases

See Note 3 to the financial statements of Southern Company Gas under "Regulatory Matters – Base Rate Cases" in Item 8 of the Form 10-K for additional information.

Settled Base Rate Cases

On February 21, 2017, the Georgia PSC approved the Georgia Rate Adjustment Mechanism (GRAM) and a $20 million increase in annual base rate revenues for Atlanta Gas Light, effective March 1, 2017. GRAM adjusts base rates annually, up or down, based on the previously approved ROE of 10.75% and does not collect revenue through special riders and surcharges. Various infrastructure programs previously authorized by the Georgia PSC under Atlanta Gas Light's STRIDE program, which include the Integrated Vintage Plastic Replacement Program,

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
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Integrated System Reinforcement Program, and Integrated Customer Growth Program, will continue under GRAM and the recovery of and return on the infrastructure program investments will be included in annual base rate adjustments. The Georgia PSC will review Atlanta Gas Light's performance annually under GRAM.

Beginning with the next rate adjustment in June 2018, Atlanta Gas Light's recovery of the previously unrecovered Pipeline Replacement Program revenue through 2014, as well as the mitigation costs associated with the Pipeline Replacement Program that were not previously included in its rates, will also be included in GRAM. In connection with the GRAM approval, the last monthly Pipeline Replacement Program surcharge increase became effective March 1, 2017.

In September 2016, Elizabethtown Gas filed a general base rate case with the New Jersey BPU requesting a $19 million increase in annual base rate revenues. The requested increase was based on a projected 12 -month test year ending March 31, 2017 and a ROE of 10.25% . On June 30, 2017, the New Jersey BPU approved a settlement that provides for a $13 million increase in annual base rate revenues, effective July 1, 2017, based on a ROE of 9.6% . Also included in the settlement was a new composite depreciation rate that is expected to result in a $3 million annual reduction of depreciation.

Pending Base Rate Cases

On March 10, 2017, Nicor Gas filed a general base rate case with the Illinois Commission requesting a $208 million increase in annual base rate revenues. The requested increase is based on a 2018 projected test year and a ROE of 10.7% . The Illinois Commission is expected to rule on the requested increase within the 11 -month statutory time limit, after which rate adjustments will be effective.

On March 31, 2017, Virginia Natural Gas filed a general base rate case with the Virginia Commission requesting a $44 million increase in annual base rate revenues. The requested increase is based on a projected 12 -month test year beginning September 1, 2017 and a ROE of 10.25% . The requested increase includes $13 million related to the recovery of investments under the Steps to Advance Virginia's Energy (SAVE) program. The Virginia Commission is expected to rule on the requested increase in the first quarter 2018. Rate adjustments are expected to be effective September 1, 2017, subject to refund.

The ultimate outcome of these pending base rate cases cannot be determined at this time.

Regulatory Infrastructure Programs

Southern Company Gas is engaged in various infrastructure programs that update or expand its gas distribution systems to improve reliability and ensure the safety of its utility infrastructure, and recovers in rates its investment and a return associated with these infrastructure programs. See Note 3 to the financial statements of Southern Company and Southern Company Gas under "Regulatory Matters – Southern Company Gas – Regulatory Infrastructure Programs" and "Regulatory Matters – Regulatory Infrastructure Programs," respectively, in Item 8 of the Form 10-K for additional information.

Nicor Gas

In 2014, the Illinois Commission approved Nicor Gas' nine -year regulatory infrastructure program, Investing in Illinois. Under this program, Nicor Gas placed into service $75 million of qualifying assets during the first six months of 2017 .

Atlanta Gas Light

Atlanta Gas Light's STRIDE program, which started in 2009, consists of three individual programs that update and expand gas distribution systems and liquefied natural gas facilities as well as improve system reliability to meet operational flexibility and customer growth. Through the programs under STRIDE, Atlanta Gas Light invested $94 million during the first six months of 2017 .

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
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In August 2016, Atlanta Gas Light filed a petition with the Georgia PSC for approval of a four -year extension of its Integrated System Reinforcement Program (i-SRP) seeking approval to invest an additional $177 million to improve and upgrade its core gas distribution system in years 2017 through 2020.

The recovery of and return on current and future capital investments under the STRIDE program will be included in the annual base rate revenue adjustment under GRAM rather than a separate surcharge. The proposed capital investments associated with the extension of i-SRP were included in the 2017 annual base rate revenue under GRAM that was approved by the Georgia PSC on February 21, 2017. See "Base Rate Cases" herein for additional information.

Elizabethtown Gas

In 2013, the New Jersey BPU approved the extension of Elizabethtown Gas' Aging Infrastructure Replacement program, under which Elizabethtown Gas invested $12 million during the first six months of 2017 .

Virginia Natural Gas

In March 2016, the Virginia Commission approved an extension to the SAVE program, under which Virginia Natural Gas invested $14 million during the first six months of 2017 .

Florida City Gas

The Florida PSC approved Florida City Gas' Safety, Access, and Facility Enhancement program in 2015. Under the program, Florida City Gas invested $7 million during the first six months of 2017 .

Integrated Coal Gasification Combined Cycle

See Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K for information regarding Mississippi Power's construction of the Kemper IGCC.

Kemper IGCC Overview

The Kemper IGCC was designed to utilize IGCC technology with an expected output capacity of 582 MWs and to be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by Mississippi Power and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation in 2013. In connection with the Kemper IGCC, Mississippi Power constructed approximately 61 miles of CO_2 pipeline infrastructure for the transport of captured CO_2 for use in enhanced oil recovery.

Kemper IGCC Schedule and Cost Estimate

In 2012, the Mississippi PSC issued the 2012 MPSC CPCN Order, a detailed order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC. The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC CPCN Order was $2.4 billion , net of $245 million of grants awarded to the Kemper IGCC project by the DOE under the Clean Coal Power Initiative Round 2 (Initial DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and AFUDC related to the Kemper IGCC. The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion , with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. The Kemper IGCC was originally projected to be placed in service in May 2014. Mississippi Power placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service in August 2014. The remainder of the plant includes the gasifiers and the gas clean-up facilities. The initial production of syngas began on July 14, 2016 for gasifier "B" and on September 13, 2016 for gasifier "A." Mississippi Power achieved integrated operation of both gasifiers on January 29, 2017, including the production of electricity from syngas in both combustion turbines. During testing, the plant produced and captured CO_2 , and produced sulfuric acid and ammonia, each of acceptable quality under the related off-take agreements. However, Mississippi Power experienced numerous challenges during the extended start-up process to achieve integrated operation of the

gasifiers on a sustained basis. Most recently, in May 2017, after achieving these milestones, Mississippi Power determined that a critical system component, the syngas coolers, would need replacement sooner than originally planned, which would require significant lead time and significant cost. In addition, the long-term natural gas price forecast has decreased significantly and the estimated cost of operating and maintaining the facility during the first five full years of operations increased significantly since certification.

On June 21, 2017, the Mississippi PSC stated its intent to issue an order (which occurred on July 6, 2017) directing Mississippi Power to pursue a settlement under which the Kemper County energy facility would be operated as a natural gas plant, rather than an IGCC plant, and address all issues associated with the Kemper IGCC (Kemper Settlement Order). On June 28, 2017, Mississippi Power notified the Mississippi PSC that it would begin a process to suspend operations and start-up activities on the gasifier portion of the Kemper IGCC, given the uncertainty as to the future of the gasifier portion of the Kemper IGCC. Mississippi Power expects to continue to operate the combined cycle portion of the Kemper IGCC as it has done since August 2014.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued) (UNAUDITED)

Mississippi Power's Kemper IGCC 2010 project estimate, cost estimate at the time of project suspension (which includes the impacts of the Mississippi Supreme Court's (Court) decision discussed herein under "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order"), and actual costs incurred as of June 30, 2017 , all of which include 100% of the costs for the Kemper IGCC, are as follows:

Cost Category	2010 Project Estimate [(a)]	Cost Estimate at Suspension [(b)]	**June 30, 2017 Actual Costs**
		(in billions)	
Plant Subject to Cost Cap [(c)(e)]	$ 2.40	$ 5.95	**$ 5.68**
Lignite Mine and Equipment	0.21	0.23	**0.23**
CO_2 Pipeline Facilities	0.14	0.11	**0.11**
AFUDC [(d)]	0.17	0.85	**0.85**
Combined Cycle and Related Assets Placed in Service – Incremental [(e)]	—	0.05	**0.05**
General Exceptions	0.05	0.10	**0.08**
Deferred Costs [(e)]	—	0.23	**0.23**
Additional DOE Grants [(f)]	—	(0.14)	**(0.14)**
Total Kemper IGCC	$ 2.97	$ 7.38	**$ 7.09**

(a) Represents the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities approved in 2011 by the Mississippi PSC, as well as the lignite mine and equipment, AFUDC, and general exceptions.

(b) Represents actual costs through June 30, 2017 and projected costs at the time of project suspension, including estimated post-in-service costs which were expected to be subject to the cost cap.

(c) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion , net of the Initial DOE Grants and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions). The Cost Estimate at Suspension and the Actual Costs include non-incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service in August 2014 that are subject to the $2.88 billion cost cap and exclude post-in-service costs for the lignite mine. See " Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order " herein for additional information.

(d) Mississippi Power's 2010 Project Estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC as described in " Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order ." The Cost Estimate at Suspension also reflects the impact of a settlement agreement with the wholesale customers for cost-based rates under FERC's jurisdiction. See " FERC Matters " herein for additional information.

(e) Non-capital Kemper IGCC-related costs incurred during construction were initially deferred as regulatory assets. Some of these costs are included in current rates and are being recognized through income; however, such costs remained in the Cost Estimate at Suspension and are reflected in the Actual Costs at June 30, 2017 . The equity return associated with assets placed in service and other non-CWIP accounts deferred for regulatory purposes, as well as the wholesale portion of debt carrying costs, whether deferred or recognized through income, was not included in the Cost Estimate at Suspension or in the Actual Costs at June 30, 2017 . At June 30, 2017, such deferred amounts totaled $33 million and $1 million , respectively.

(f) On April 8, 2016, Mississippi Power received approximately $137 million in additional grants from the DOE for the Kemper IGCC (Additional DOE Grants).

Mississippi Power recorded pre-tax charges to income for revisions to the cost estimate of $196 million ($121 million after tax) in the second quarter through May 31, 2017 and a total of $305 million ($188 million after tax) for year-to-date through May 31, 2017. In the aggregate, Mississippi Power incurred charges of $3.07 billion ($1.89 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through May 31, 2017. The May 31, 2017 cost estimate included approximately $175 million of estimated costs to be incurred beyond the then-estimated in-service date of June 30, 2017 that were expected to be subject to the $2.88 billion cost cap.

**NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
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While the ultimate disposition of the gasification portions of the Kemper IGCC remains subject to the Mississippi PSC's jurisdiction, including the potential resolution of the matters addressed in the Kemper Settlement Order, given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility, cost recovery of the gasification portions is no longer probable; therefore, Mississippi Power recorded an additional charge to income in June 2017 of $2.8 billion ($2.0 billion after tax), which includes estimated costs associated with the gasification portions of the plant and lignite mine. In the event the gasification portions of the project are ultimately canceled, additional pre-tax costs currently estimated at approximately $100 million to $200 million are expected to be incurred.

In the aggregate, Mississippi Power recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC totaling $3.0 billion for the second quarter 2017 and $3.1 billion for the six months ended June 30, 2017.

As of June 30, 2017, Mississippi Power has recorded a total of approximately $1.3 billion in costs associated with the combined cycle portion of the Kemper IGCC, of which $1.2 billion is included in plant in service, $14 million in materials and supplies, $22 million in other regulatory assets, current, and $95 million in other regulatory assets, deferred.

Rate Recovery of Kemper IGCC Costs

Given the variety of potential scenarios and the uncertainty of the outcome of future regulatory proceedings with the Mississippi PSC (and any subsequent related legal challenges), the ultimate outcome of the rate recovery matters discussed herein, including the resolution of legal challenges, cannot now be determined but could result in further material charges that could have a material impact on Southern Company's and Mississippi Power's results of operations, financial condition, and liquidity.

Kemper IGCC Settlement Docket

On June 21, 2017, the Mississippi PSC stated its intent to issue an order (which occurred on July 6, 2017) directing Mississippi Power to pursue a settlement under which the Kemper County energy facility would be operated as a natural gas plant, rather than an IGCC plant, and address all issues associated with the Kemper IGCC. The Kemper Settlement Order established a new docket for the purposes of pursuing a global settlement of costs of the Kemper IGCC (Kemper IGCC Settlement Docket). The Mississippi PSC requested any such proposed settlement agreement reflect: (i) at a minimum, no rate increase to Mississippi Power customers (with a rate reduction focused on residential customers encouraged); (ii) removal of all cost risk to customers associated with the Kemper IGCC gasifier and related assets; and (iii) modification or amendment of the CPCN for the Kemper IGCC to allow only for ownership and operation of a natural gas facility. The Kemper Settlement Order provides that any related settlement agreement be filed within 45 days from the effective date of the Kemper Settlement Order. If a settlement agreement is filed, a hearing will be set 45 days from the date of the settlement's filing, and the appropriate scheduling order will be established.

Although the ability to achieve a negotiated settlement is uncertain, Mississippi Power intends to pursue any available settlement alternatives. In addition, the Kemper Settlement Order provides that, in the event a settlement agreement is not reached, the Mississippi PSC reserves its right to take any appropriate steps, including issuing an order to show cause as to why the CPCN for the Kemper IGCC should not be revoked.

On June 28, 2017, Mississippi Power notified the Mississippi PSC that it would begin a process to suspend operations and start-up activities on the gasifier portion of the Kemper IGCC, given the uncertainty as to the future of the gasifier portion of the Kemper IGCC. Mississippi Power expects to continue to operate the combined cycle portion of the Kemper IGCC as it has done since August 2014.

At June 30, 2017, approximately $3.3 billion in actual Kemper IGCC costs were not reflected in Mississippi Power's retail and wholesale rates, of which $0.5 billion was related to the combined cycle and associated facilities and $2.8 billion was related to the gasification portions of the Kemper IGCC.

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While the ultimate disposition of the gasification portions of the Kemper IGCC remains subject to the Mississippi PSC's jurisdiction, including the potential resolution of the matters addressed in the Kemper Settlement Order, given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility, cost recovery of the gasification portions is no longer probable; therefore, Mississippi Power recorded an additional charge to income in June 2017 of $2.8 billion ($2.0 billion after tax), which includes estimated costs associated with the gasification portions of the plant and lignite mine. In the event the gasification portions of the project are ultimately canceled, additional pre-tax costs currently estimated at approximately $100 million to $200 million are expected to be incurred.

As of June 30, 2017, Mississippi Power has recorded a total of approximately $1.3 billion in costs associated with the combined cycle portion of the Kemper IGCC including transmission and related regulatory assets, of which $0.8 billion is included in retail and wholesale rates. The $0.5 billion not included in current rates includes costs in excess of the original 2010 estimate for the combined cycle portion of the facility, as well as the 15% that was previously contracted to SMEPA. Mississippi Power has calculated the revenue requirements resulting from these remaining costs, using reasonable assumptions for amortization periods, and expects them to be recovered through rates consistent with the Mississippi PSC's requested settlement conditions. The ultimate outcome will be determined by the Mississippi PSC in the Kemper IGCC Settlement Docket proceedings.

Prudence

On August 17, 2016, the Mississippi PSC issued an order establishing a discovery docket to manage all filings related to the prudence of the Kemper IGCC. On October 3, 2016, Mississippi Power made a required compliance filing, which included a review and explanation of differences between the Kemper IGCC project estimate set forth in the 2010 CPCN proceedings and the most recent Kemper IGCC project estimate, as well as comparisons of current cost estimates and current expected plant operational parameters to the estimates presented in the 2010 CPCN proceedings for the first five years after the Kemper IGCC is placed in service. Compared to amounts presented in the 2010 CPCN proceedings, operations and maintenance expenses have increased an average of $105 million annually and maintenance capital has increased an average of $44 million annually for the first full five years of operations for the Kemper IGCC. Additionally, while the current estimated operational availability estimates reflect ultimate results similar to those presented in the 2010 CPCN proceedings, the ramp up period for the current estimates reflects a lower starting point and a slower escalation rate. On November 17, 2016, Mississippi Power submitted a supplemental filing to the October 3, 2016 compliance filing to present revised non-fuel operations and maintenance expense projections for the first year after the Kemper IGCC is placed in service. This supplemental filing included approximately $68 million in additional estimated operations and maintenance costs expected to be required to support the operations of the Kemper IGCC during that period.

Mississippi Power responded to numerous requests for information from interested parties in the discovery docket, which is now complete. Mississippi Power expects the Mississippi PSC to utilize this information in connection with the ultimate resolution of Kemper IGCC cost recovery.

Economic Viability Analysis

In the fourth quarter 2016, as a part of its Integrated Resource Plan process, the Southern Company system completed its regular annual updated fuel forecast, the 2017 Annual Fuel Forecast. This updated fuel forecast reflected significantly lower long-term estimated costs for natural gas than were previously projected. As a result of the updated long-term natural gas forecast, as well as the revised operating expense projections reflected in the discovery docket filings discussed above, on February 21, 2017, Mississippi Power filed an updated project economic viability analysis of the Kemper IGCC as required under the 2012 MPSC CPCN Order confirming authorization of the Kemper IGCC. The project economic viability analysis measures the life cycle economics of the Kemper IGCC compared to feasible alternatives, natural gas combined cycle generating units, under a variety of scenarios and considering fuel, operating and capital costs, and operating characteristics, as well as federal and state taxes and incentives. The reduction in the projected long-term natural gas prices in the 2017 Annual Fuel Forecast

and, to a lesser extent, the increase in the estimated Kemper IGCC operating costs, negatively impact the updated project economic viability analysis.

Mississippi Power expects the Mississippi PSC to address this matter in connection with the Kemper IGCC Settlement Docket.

2015 Rate Case

On August 13, 2015, the Mississippi PSC approved Mississippi Power's request for interim rates, which presented an alternative rate proposal (In-Service Asset Proposal) designed to recover Mississippi Power's costs associated with the Kemper IGCC assets that are commercially operational and currently providing service to customers (the transmission facilities, combined cycle, natural gas pipeline, and water pipeline) and other related costs. The interim rates were designed to collect approximately $159 million annually and became effective in September 2015, subject to refund and certain other conditions.

On December 3, 2015, the Mississippi PSC issued the In-Service Asset Rate Order adopting in full a stipulation (2015 Stipulation) entered into between Mississippi Power and the MPUS regarding the In-Service Asset Proposal. The In-Service Asset Rate Order provided for retail rate recovery of an annual revenue requirement of approximately $126 million , based on Mississippi Power's actual average capital structure, with a maximum common equity percentage of 49.733% , a 9.225% return on common equity, and actual embedded interest costs. The In-Service Asset Rate Order also included a prudence finding of all costs in the stipulated revenue requirement calculation for the in-service assets. The stipulated revenue requirement excluded the costs of the Kemper IGCC related to the 15% undivided interest that was previously projected to be purchased by SMEPA but reserved Mississippi Power's right to seek recovery in a future proceeding. See " Termination of Proposed Sale of Undivided Interest " herein for additional information. With implementation of the new rates on December 17, 2015, the interim rates were terminated and, in March 2016, Mississippi Power completed customer refunds of approximately $11 million for the difference between the interim rates collected and the permanent rates.

In 2011, the Mississippi PSC authorized Mississippi Power to defer all non-capital Kemper IGCC-related costs to a regulatory asset through the in-service date. In connection with the implementation of the In-Service Asset Order and wholesale rates, Mississippi Power began expensing certain ongoing project costs and certain retail debt carrying costs that previously were deferred and began amortizing certain regulatory assets associated with assets placed in service and consulting and legal fees. The amortization periods for these regulatory assets vary from two years to 10 years as set forth in the In-Service Asset Rate Order and the settlement agreement with wholesale customers. As of June 30, 2017, the balance associated with these regulatory assets was $117 million , of which $22 million is included in current assets. See "FERC Matters" herein for additional information related to the 2016 settlement agreement with wholesale customers.

The In-Service Asset Rate Order requires Mississippi Power to submit an annual true-up calculation of its actual cost of capital, compared to the stipulated total cost of capital, with the first occurring as of May 31, 2016. At June 30, 2017, Mississippi Power's related regulatory liability included in its balance sheet totaled approximately $10 million .

As required by the In-Service Asset Rate Order, on June 5, 2017, Mississippi Power made a rate filing requesting to adjust the amortization schedules of the regulatory assets reviewed and determined prudent in the In-Service Asset Order in a manner that would not change customer rates or annual revenues. On June 28, 2017, the Mississippi PSC suspended this filing. On July 6, 2017, the Mississippi PSC issued an order requiring Mississippi Power to establish a regulatory liability account to maintain current rates related to the Kemper IGCC following the July 2017 completion of the amortization period for certain regulatory assets approved in the In-Service Asset Rate Order that would allow for subsequent refund if the Mississippi PSC deems the rates unjust and unreasonable.

2013 MPSC Rate Order

In January 2013, Mississippi Power entered into a settlement agreement with the Mississippi PSC that was intended to establish the process for resolving matters regarding cost recovery related to the Kemper IGCC (2013 Settlement

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
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Agreement). Under the 2013 Settlement Agreement, Mississippi Power agreed to limit the portion of prudently-incurred Kemper IGCC costs to be included in retail rate base to the $2.4 billion certificated cost estimate, plus the Cost Cap Exceptions, but excluding AFUDC, and any other costs permitted or determined to be excluded from the $2.88 billion cost cap by the Mississippi PSC. In March 2013, the Mississippi PSC issued a rate order approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014 (2013 MPSC Rate Order) to be used to mitigate customer rate impacts after the Kemper IGCC was placed in service, based on a mirror CWIP methodology (Mirror CWIP rate).

On February 12, 2015, the Court reversed the 2013 MPSC Rate Order and, on July 7, 2015, the Mississippi PSC ordered that the Mirror CWIP rate be terminated effective July 20, 2015 and required the fourth quarter 2015 refund of the $342 million previously collected, along with associated carrying costs of $29 million .

Because the 2013 MPSC Rate Order did not provide for the inclusion of CWIP in rate base as permitted by the Baseload Act, Mississippi Power continued to record AFUDC on the Kemper IGCC. Between the original May 2014 estimated in-service date and the June 2017 project suspension date, Mississippi Power recorded $493 million of AFUDC on the Kemper IGCC subject to the $2.88 billion cost cap and Cost Cap Exception amounts, of which $459 million related to the gasification portions of the Kemper IGCC.

Mississippi Power expects the Mississippi PSC to address this matter in connection with the Kemper IGCC Settlement Docket.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, Mississippi Power owns the lignite mine and equipment and mineral reserves located around the Kemper IGCC site. The mine started commercial operation in June 2013.

In 2010, Mississippi Power executed a 40 -year management fee contract with Liberty Fuels Company, LLC (Liberty Fuels), a wholly-owned subsidiary of The North American Coal Corporation, which developed, constructed, and is responsible for the mining operations through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and Mississippi Power has a contractual obligation to fund all reclamation activities. In addition to the obligation to fund the reclamation activities, Mississippi Power provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses. See Note 1 to the financial statements of Mississippi Power under "Asset Retirement Obligations and Other Costs of Removal" and "Variable Interest Entities" in Item 8 of the Form 10-K for additional information.

In addition, Mississippi Power constructed the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. Mississippi Power entered into agreements with Denbury Onshore (Denbury) and Treetop Midstream Services, LLC (Treetop), pursuant to which Denbury would purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop would purchase 30% of the CO_2 captured from the Kemper IGCC. On June 3, 2016, Mississippi Power cancelled its contract with Treetop and amended its contract with Denbury to reflect, among other things, Denbury's agreement to purchase 100% of the CO_2 captured from the Kemper IGCC and an initial contract term of 16 years. Denbury has the right to terminate the contract at any time because Mississippi Power did not place the Kemper IGCC in service by July 1, 2017.

The ultimate outcome of these matters cannot be determined at this time.

Termination of Proposed Sale of Undivided Interest

In 2010 and as amended in 2012, Mississippi Power and SMEPA entered into an agreement whereby SMEPA agreed to purchase a 15% undivided interest in the Kemper IGCC (15% Undivided Interest). On May 20, 2015, SMEPA notified Mississippi Power of its termination of the agreement. Mississippi Power previously received a total of $275 million of deposits from SMEPA that were required to be returned to SMEPA with interest. On June 3, 2015, Southern Company, pursuant to its guarantee obligation, returned approximately $301 million to SMEPA.

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Subsequently, Mississippi Power issued a promissory note in the aggregate principal amount of approximately $301 million to Southern Company, which was repaid in June 2017.

Litigation

On April 26, 2016, a complaint against Mississippi Power was filed in Harrison County Circuit Court (Circuit Court) by Biloxi Freezing & Processing Inc., Gulfside Casino Partnership, and John Carlton Dean, which was amended and refiled on July 11, 2016 to include, among other things, Southern Company as a defendant. The individual plaintiff alleges that Mississippi Power and Southern Company violated the Mississippi Unfair Trade Practices Act. All plaintiffs have alleged that Mississippi Power and Southern Company concealed, falsely represented, and failed to fully disclose important facts concerning the cost and schedule of the Kemper IGCC and that these alleged breaches have unjustly enriched Mississippi Power and Southern Company. The plaintiffs seek unspecified actual damages and punitive damages; ask the Circuit Court to appoint a receiver to oversee, operate, manage, and otherwise control all affairs relating to the Kemper IGCC; ask the Circuit Court to revoke any licenses or certificates authorizing Mississippi Power or Southern Company to engage in any business related to the Kemper IGCC in Mississippi; and seek attorney's fees, costs, and interest. The plaintiffs also seek an injunction to prevent any Kemper IGCC costs from being charged to customers through electric rates. On June 23, 2017, the Circuit Court ruled in favor of motions by Southern Company and Mississippi Power and dismissed the case. On July 7, 2017, the plaintiffs filed notice to appeal to the Court.

On June 9, 2016, Treetop, Greenleaf CO_2 Solutions, LLC (Greenleaf), Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group filed a complaint against Mississippi Power, Southern Company, and SCS in the state court in Gwinnett County, Georgia. The complaint relates to the cancelled CO_2 contract with Treetop and alleges fraudulent misrepresentation, fraudulent concealment, civil conspiracy, and breach of contract on the part of Mississippi Power, Southern Company, and SCS and seeks compensatory damages of $100 million , as well as unspecified punitive damages. Southern Company, Mississippi Power, and SCS have moved to compel arbitration pursuant to the terms of the CO_2 contract, which the court granted on May 4, 2017. On June 28, 2017, Treetop, Greenleaf, Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group filed a claim for arbitration requesting $500 million in damages.

Southern Company and Mississippi Power believe these legal challenges have no merit; however, an adverse outcome in these proceedings could have a material impact on Southern Company's and Mississippi Power's results of operations, financial condition, and liquidity. Southern Company and Mississippi Power will vigorously defend themselves in these matters, and the ultimate outcome of these matters cannot be determined at this time.

Baseload Act

In 2008, the Baseload Act was signed by the Governor of Mississippi. The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently-incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant.

Income Tax Matters

See Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle – Bonus Depreciation," " – Investment Tax Credits," and " – Section 174 Research and Experimental Deduction" in Item 8 of the Form 10-K and Note (G) under " Section 174 Research and

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Experimental Deduction " for additional information on bonus depreciation, investment tax credits, and the Section 174 research and experimental deduction.

Bonus Depreciation

Approximately $370 million of positive cash flows is expected to result from bonus depreciation for the 2017 tax year, but may not all be realized in 2017 due to net operating loss projections for the 2017 tax year, and is dependent upon placing the remainder of the Kemper IGCC in service by December 31, 2017. If the suspension of the Kemper IGCC start-up activities results in an abandonment, any amount previously estimated as bonus depreciation would be claimed as a deduction under IRC Section 165. As of June 30, 2017, $82 million has been received through quarterly income tax refunds for bonus depreciation related to the Kemper IGCC, which may be subject to repayment. See Note (G) for additional information. The ultimate outcome of this matter cannot be determined at this time.

Section 174 Research and Experimental Deduction

Southern Company, on behalf of Mississippi Power, has reflected deductions for research and experimental (R&E) expenditures related to the Kemper IGCC in its federal income tax calculations since 2013 and filed amended federal income tax returns for 2008 through 2013 to also include such deductions. In December 2016, Southern Company and the IRS reached a proposed settlement, subject to approval of the U.S. Congress Joint Committee on Taxation, resolving a methodology for these deductions. Due to the uncertainty related to this tax position, Southern Company and Mississippi Power had unrecognized tax benefits associated with these R&E deductions totaling approximately $464 million as of June 30, 2017. If the suspension of the Kemper IGCC start-up activities results in an abandonment, any amount not allowed under IRC Section 174 would be claimed as a deduction under IRC Section 165, and would result in a reversal of the related unrecognized tax benefits, excluding interest. See Note (G) for additional information. This matter is expected to be resolved in the next 12 months; however, the ultimate outcome of this matter cannot be determined at this time.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
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(C) FAIR VALUE MEASUREMENTS

As of June 30, 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 June 30, 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)		
Southern Company					
Assets:					
Energy-related derivatives [(a)(b)]	$ 193	$ 179	$ —	$ —	$ 372
Interest rate derivatives	—	11	—	—	11
Foreign currency derivatives	—	56	—	—	56
Nuclear decommissioning trusts [(c)]	728	966	—	25	1,719
Cash equivalents	834	—	—	—	834
Other investments	9	—	1	—	10
Total	$ 1,764	$ 1,212	$ 1	$ 25	$ 3,002
Liabilities:					
Energy-related derivatives [(a)(b)]	$ 205	$ 161	$ —	$ —	$ 366
Interest rate derivatives	—	23	—	—	23
Foreign currency derivatives	—	23	—	—	23
Contingent consideration	—	—	20	—	20
Total	$ 205	$ 207	$ 20	$ —	$ 432
Alabama Power					
Assets:					
Energy-related derivatives	$ —	$ 9	$ —	$ —	$ 9
Nuclear decommissioning trusts: [(d)]					
Domestic equity	411	79	—	—	490
Foreign equity	56	54	—	—	110
U.S. Treasury and government agency securities	—	29	—	—	29
Corporate bonds	22	145	—	—	167
Mortgage and asset backed securities	—	18	—	—	18
Private Equity	—	—	—	25	25
Other	—	6	—	—	6
Cash equivalents	493	—	—	—	493
Total	$ 982	$ 340	$ —	$ 25	$ 1,347
Liabilities:					
Energy-related derivatives	$ —	$ 11	$ —	$ —	$ 11

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
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	Fair Value Measurements Using:				
As of June 30, 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)		
Georgia Power					
Assets:					
Energy-related derivatives	$ —	$ 15	$ —	$ —	$ 15
Interest rate derivatives	—	1	—	—	1
Nuclear decommissioning trusts: [d] [e]					
Domestic equity	225	1	—	—	226
Foreign equity	—	147	—	—	147
U.S. Treasury and government agency securities	—	198	—	—	198
Municipal bonds	—	72	—	—	72
Corporate bonds	—	169	—	—	169
Mortgage and asset backed securities	—	41	—	—	41
Other	14	7	—	—	21
Cash equivalents	50	—	—	—	50
Total	$ 289	$ 651	$ —	$ —	$ 940
Liabilities:					
Energy-related derivatives	$ —	$ 14	$ —	$ —	$ 14
Interest rate derivatives	—	3	—	—	3
Total	$ —	$ 17	$ —	$ —	$ 17
Gulf Power					
Assets:					
Energy-related derivatives	$ —	$ 1	$ —	$ —	$ 1
Cash equivalents	21	—	—	—	21
Total	$ 21	$ 1	$ —	$ —	$ 22
Liabilities:					
Energy-related derivatives	$ —	$ 29	$ —	$ —	$ 29
Mississippi Power					
Assets:					
Energy-related derivatives	$ —	$ 2	$ —	$ —	$ 2
Interest rate derivatives	—	3	—	—	3
Cash equivalents	100	—	—	—	100
Total	$ 100	$ 5	$ —	$ —	$ 105
Liabilities:					
Energy-related derivatives	$ —	$ 10	$ —	$ —	$ 10

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
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	Fair Value Measurements Using:				
As of June 30, 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)		
Southern Power					
Assets:					
Energy-related derivatives	$ —	$ 14	$ —	$ —	$ 14
Foreign currency derivatives	—	56	—	—	56
Total	$ —	$ 70	$ —	$ —	$ 70
Liabilities:					
Energy-related derivatives	$ —	$ 9	$ —	$ —	$ 9
Foreign currency derivatives	—	23	—	—	23
Contingent consideration	—	—	20	—	20
Total	$ —	$ 32	$ 20	$ —	$ 52
Southern Company Gas					
Assets:					
Energy-related derivatives [(a)(b)]	$ 193	$ 138	$ —	$ —	$ 331
Liabilities:					
Energy-related derivatives [(a)(b)]	$ 205	$ 86	$ —	$ —	$ 291

(a) Excludes $11 million associated with certain weather derivatives accounted for based on intrinsic value rather than fair value.

(b) Excludes cash collateral of $71 million .

(c) For additional detail, see the nuclear decommissioning trusts sections for Alabama Power and Georgia Power in this table.

(d) Excludes receivables related to investment income, pending investment sales, payables related to pending investment purchases, and currencies.

(e) Includes the investment securities pledged to creditors and collateral received and excludes payables related to the securities lending program. As of June 30, 2017 , approximately $38 million of the fair market value of Georgia Power's nuclear decommissioning trust funds' securities were on loan to creditors under the funds' managers' securities lending program.

Southern Company, Alabama Power, and Georgia Power continue to elect the option to fair value investment securities held in the nuclear decommissioning trust funds. The fair value of the funds at Southern Company, including reinvested interest and dividends and excluding the funds' expenses, increased by $55 million and $118 million , respectively, for the three and six months ended June 30, 2017 , and by $47 million and $67 million , respectively, for the three and six months ended June 30, 2016 . Alabama Power recorded an increase in fair value of $28 million and $62 million , respectively, for the three and six months ended June 30, 2017 and $29 million and $40 million , respectively, for the three and six months ended June 30, 2016 as a change in regulatory liabilities related to its AROs. Georgia Power recorded increases in fair value of $27 million and $56 million , respectively, for the three and six months ended June 30, 2017 and $18 million and $27 million , respectively, for the three and six months ended June 30, 2016 as a change in its regulatory asset related to its AROs.

Valuation Methodologies

The energy-related derivatives primarily consist of exchange-traded and 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

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
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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 fair value of cross-currency swaps reflects the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future foreign currency exchange rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and discount rates. The interest rate derivatives and cross-currency swaps are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note (H) for additional information on how these derivatives are used.

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. For fair value measurements of the investments within the nuclear decommissioning trusts, external pricing vendors are designated for each asset class with each security specifically assigned a primary pricing source. For investments held within commingled funds, fair value is determined at the end of each business day through the net asset value, which is established by obtaining the underlying securities' individual prices from the primary pricing source. A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, fixed income market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information, including live trading levels and pricing analysts' judgments, are also obtained when available. See Note 1 to the financial statements of Southern Company, Alabama Power, and Georgia Power under "Nuclear Decommissioning" in Item 8 of the Form 10-K for additional information.

Southern Power has contingent payment obligations related to certain acquisitions whereby Southern Power is obligated to make generation-based payments to the seller over a period ranging from 10 to 30 years, beginning at the commercial operation date. The obligation is categorized as Level 3 under Fair Value Measurements as the fair value is determined using significant unobservable inputs for the forecasted facility generation in MW-hours, as well as other inputs such as a fixed dollar amount per MW-hour, and a discount rate, and is evaluated periodically. The fair value of contingent consideration reflects the net present value of expected payments and any periodic change arising from forecasted generation is expected to be immaterial.

"Other investments" include investments that are not traded in the open market. The fair value of these investments has been determined based on market factors including comparable multiples and the expectations regarding cash flows and business plan executions.

As of June 30, 2017 , the fair value measurements of private equity investments held in the nuclear decommissioning trust that are calculated at net asset value per share (or its equivalent) as a practical expedient, as well as the nature and risks of those investments, were as follows:

As of June 30, 2017:	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
	(in millions)			
Southern Company	$ 25	$ 22	Not Applicable	Not Applicable
Alabama Power	$ 25	$ 22	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 are expected to occur at various times over the next 10 years .

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As of June 30, 2017 , 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:		
Southern Company	$ 46,631	$ 48,228
Alabama Power	$ 7,440	$ 8,041
Georgia Power	$ 10,888	$ 11,585
Gulf Power	$ 1,292	$ 1,336
Mississippi Power	$ 2,125	$ 2,071
Southern Power	$ 5,725	$ 5,878
Southern Company Gas	$ 5,699	$ 6,031

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates available to Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and Southern Company Gas.

(D) STOCKHOLDERS' EQUITY

Earnings per Share

For Southern Company, the only difference in computing basic and diluted earnings per share is attributable to awards outstanding under the stock option and performance share plans. See Note 8 to the financial statements of Southern Company in Item 8 of the Form 10-K for information on the stock option and performance share plans. The effect of both stock options and performance share award units was determined using the treasury stock method. Shares used to compute diluted earnings per share were as follows:

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	**Six Months Ended June 30, 2017**	Six Months Ended June 30, 2016
		(in millions)		
As reported shares	**998**	934	**996**	925
Effect of options and performance share award units	**7**	6	**7**	6
Diluted shares	**1,005**	940	**1,003**	931

Stock options and performance share award units that were not included in the diluted earnings per share calculation because they were anti-dilutive were immaterial for the three and six months ended June 30, 2017 and 2016 .

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued) (UNAUDITED)

Changes in Stockholders' Equity

The following table presents year-to-date changes in stockholders' equity of Southern Company:

	Number of Common Shares		Common Stockholders' Equity	Preferred and Preference Stock of Subsidiaries	Noncontrolling Interests [*]	Total Stockholders' Equity
	Issued	Treasury				
	(in thousands)		(in millions)			
Balance at December 31, 2016	991,213	(819)	$ 24,758	$ 609	$ 1,245	$ 26,612
Consolidated net income (loss) attributable to Southern Company	—	—	(723)	—	—	(723)
Other comprehensive income (loss)	—	—	(11)	—	—	(11)
Stock issued	9,129	—	417	—	—	417
Stock-based compensation	—	—	72	—	—	72
Cash dividends on common stock	—	—	(1,134)	—	—	(1,134)
Preference stock redemption	—	—	—	(150)	—	(150)
Contributions from noncontrolling interests	—	—	—		71	71
Distributions to noncontrolling interests	—	—	—	—	(40)	(40)
Net income attributable to noncontrolling interests	—	—	—	—	16	16
Reclassification from redeemable noncontrolling interests	—	—	—	—	114	114
Other	—	(49)	(7)	3	1	(3)
Balance at June 30, 2017	**1,000,342**	**(868)**	**$ 23,372**	**$ 462**	**$ 1,407**	**$ 25,241**
Balance at December 31, 2015	915,073	(3,352)	$ 20,592	$ 609	$ 781	$ 21,982
Consolidated net income attributable to Southern Company	—	—	1,112	—	—	1,112
Other comprehensive income (loss)	—	—	(117)	—	—	(117)
Stock issued	27,297	2,599	1,383	—	—	1,383
Stock-based compensation	—	—	67	—	—	67
Cash dividends on common stock	—	—	(1,023)	—	—	(1,023)
Contributions from noncontrolling interests	—	—	—	—	169	169
Distributions to noncontrolling interests	—	—	—	—	(10)	(10)
Purchase of membership interests from noncontrolling interests	—	—	—	—	(129)	(129)
Net income attributable to noncontrolling interests	—	—	—	—	11	11
Other	—	(19)	1	—	—	1
Balance at June 30, 2016	942,370	(772)	$ 22,015	$ 609	$ 822	$ 23,446

(*) Related to Southern Power Company and excludes redeemable noncontrolling interests. In April 2017, approximately $114 million was reclassified from redeemable noncontrolling interests to noncontrolling interests, included in stockholder's equity, due to the expiration of SunPower Corp's option to require Southern Power to purchase its membership interests in one of the solar partnerships. See Note 10 to the financial statements of Southern Power in Item 8 of the Form 10-K for additional information.

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(E) FINANCING

Going Concern

As of June 30, 2017 , Mississippi Power's current liabilities exceeded current assets by approximately $930 million primarily due to approximately $935 million that will be required through June 30, 2018 to fund maturities of long-term debt and $17 million that will be required to fund maturities of short-term debt. In addition, Mississippi Power has $40 million of tax-exempt variable rate demand obligations that are supported by short-term credit facilities and $50 million of fixed rate pollution control revenue bonds that are required to be remarketed over the next 12 months. Mississippi Power intends to utilize operating cash flows, lines of credit, and bank term loans, as market conditions permit, as well as, under certain circumstances, commercial paper and/or equity contributions and/or loans from Southern Company to fund Mississippi Power's short-term capital needs. Specifically, Mississippi Power has been informed by Southern Company that in the event sufficient funds are not available from external sources, Southern Company intends to provide Mississippi Power with loans and/or equity contributions sufficient to fund the remaining indebtedness scheduled to mature and other cash needs over the next 12 months. Therefore, Mississippi Power's financial statement presentation contemplates continuation of Mississippi Power as a going concern as a result of Southern Company's anticipated ongoing financial support of Mississippi Power. For additional information, see Notes 1 and 6 to the financial statements of Mississippi Power under "Recently Issued Accounting Standards" and "Going Concern," respectively, in Item 8 of the Form 10-K and Note (B) under " Integrated Coal Gasification Combined Cycle ."

DOE Loan Guarantee Borrowings

See Note 6 to the financial statements of Southern Company and Georgia Power in Item 8 of the Form 10-K for additional information regarding Georgia Power's loan guarantee agreement (Loan Guarantee Agreement) with the DOE and related multi-advance term loan facility (FFB Credit Facility) with the FFB.

On July 27, 2017, Georgia Power entered into an amendment to the Loan Guarantee Agreement (LGA Amendment) in connection with the DOE's consent to Georgia Power's entry into the Services Agreement and the related intellectual property licenses (IP Licenses). The purpose of the amendment is to clarify the operation of the Loan Guarantee Agreement pending Georgia Power's completion of its comprehensive schedule, cost-to-complete, and cancellation cost assessments being prepared as a result of the bankruptcy of the EPC Contractor (Cost Assessments).

Under the terms of the Loan Guarantee Agreement, upon termination of the Vogtle 3 and 4 Agreement, further advances are conditioned upon the DOE's approval of any agreements entered into in replacement of the Vogtle 3 and 4 Agreement. Under the terms of the LGA Amendment, Georgia Power will not request any advances unless and until such time as Georgia Power has (i) completed the Cost Assessments and made a determination to continue construction of Plant Vogtle Units 3 and 4, (ii) delivered to the DOE an updated project schedule, construction budget, and other information, (iii) entered into one or more agreements with a construction contractor or contractors that will be primarily responsible for construction of Plant Vogtle Units 3 and 4 and such agreements have been approved by the DOE (together with the Services Agreement and the IP Licenses, the Replacement EPC Arrangements), and (iv) entered into a further amendment to the Loan Guarantee Agreement with the DOE to reflect the Replacement EPC Arrangements.

Upon satisfaction of the conditions described above, advances may be requested under the FFB Credit Facility on a quarterly basis through 2020. The final maturity date for each advance under the FFB Credit Facility is February 20, 2044. Interest is payable quarterly and principal payments will begin on February 20, 2020. Borrowings under the FFB Credit Facility will bear interest at the applicable U.S. Treasury rate plus a spread equal to 0.375% .

In addition to the conditions described above, future advances are subject to satisfaction of customary conditions, as well as certification of compliance with the requirements of the Title XVII Loan Guarantee Program, accuracy of project-related representations and warranties, delivery of updated project-related information, absence of liens on Georgia Power's ownership interest in Plant Vogtle Units 3 and 4 other than permitted liens, evidence of compliance

with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse Eligible Project Costs.

Under the Loan Guarantee Agreement, Georgia Power is subject to customary borrower affirmative and negative covenants and events of default. In addition, Georgia Power is subject to project-related reporting requirements and other project-specific covenants and events of default.

In the event certain mandatory prepayment events occur, the FFB's commitment to make further advances under the FFB Credit Facility will terminate and Georgia Power will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facility over a period of five years (with level principal amortization). Among other things, these mandatory prepayment events include (i) the termination of the Services Agreement or rejection of the Services Agreement in bankruptcy if Georgia Power does not maintain access to intellectual property rights under the IP Licenses; (ii) a decision by Georgia Power not to continue construction of Plant Vogtle Units 3 and 4; (iii) a failure by Georgia Power to complete the Cost Assessments or enter into Replacement EPC Arrangements by December 31, 2017; (iv) cancellation of Plant Vogtle Units 3 and 4 by the Georgia PSC, or by Georgia Power if authorized by the Georgia PSC; and (v) cost disallowances by the Georgia PSC that could have a material adverse effect on completion of Plant Vogtle Units 3 and 4 or Georgia Power's ability to repay the outstanding borrowings under the FFB Credit Facility. Under certain circumstances, insurance proceeds and any proceeds from an event of taking must be applied to immediately prepay outstanding borrowings under the FFB Credit Facility. In addition, under certain circumstances Georgia Power may be required to make additional prepayments in connection with its receipt of payments under the Guarantee Settlement Agreement or from the EPC Contractor under the Vogtle 3 and 4 Agreement. Georgia Power also may voluntarily prepay outstanding borrowings under the FFB Credit Facility. Under the FFB Credit Facility, any prepayment (whether mandatory or optional) will be made with a make-whole premium or discount, as applicable.

See Note (B) under " Regulatory Matters – Georgia Power – Nuclear Construction " for additional information regarding Plant Vogtle Units 3 and 4.

Bank Credit Arrangements

Bank credit arrangements provide liquidity support to the registrants' commercial paper borrowings and the traditional electric operating companies' pollution control revenue bonds. The amount of variable rate pollution control revenue bonds of the traditional electric operating companies outstanding requiring liquidity support as of June 30, 2017 was approximately $1.6 billion (comprised of approximately $890 million at Alabama Power, $550 million at Georgia Power, $82 million at Gulf Power, and $40 million at Mississippi Power). In June 2017, Georgia Power remarketed $318 million of variable rate pollution control bonds in index rate modes, reducing the liquidity support utilized under Georgia Power's bank credit arrangement. In addition, at June 30, 2017 , the traditional electric operating companies had approximately $626 million (comprised of approximately $436 million at Georgia Power, $140 million at Gulf Power, and $50 million at Mississippi Power) of pollution control revenue bonds outstanding that were required to be reoffered within the next 12 months. See Note 6 to the financial statements of each registrant under "Bank Credit Arrangements" in Item 8 of the Form 10-K and " Financing Activities " herein for additional information.

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The following table outlines the committed credit arrangements by company as of June 30, 2017 :

	Expires							Executable Term Loans		Expires Within One Year	
Company	2017	2018	2019	2020	2022	Total	Unused	One Year	Two Years	Term Out	No Term Out
							(in millions)				
Southern Company [(a)]	$ —	$ —	$ —	$ —	$ 2,000	$ 2,000	$ 2,000	$ —	$ —	$ —	$ —
Alabama Power	3	532	—	—	800	1,335	1,335	—	—	—	35
Georgia Power	—	—	—	—	1,750	1,750	1,732	—	—	—	—
Gulf Power	30	195	25	30	—	280	280	45	—	—	40
Mississippi Power	113	—	—	—	—	113	100	—	13	13	100
Southern Power Company	—	—	—	—	750	750	675	—	—	—	—
Southern Company Gas [(b)]	—	—	—	—	1,900	1,900	1,849	—	—	—	—
Other	10	30	—	—	—	40	40	20	—	20	20
Southern Company Consolidated	$ 156	$ 757	$ 25	$ 30	$ 7,200	$ 8,168	$ 8,011	$ 65	$ 13	$ 33	$ 195

(a) Represents the Southern Company parent entity.

(b) Southern Company Gas, as the parent entity, guarantees the obligations of Southern Company Gas Capital, which is the borrower of $1.2 billion of these arrangements. Southern Company Gas' committed credit arrangements also include $700 million for which Nicor Gas is the borrower and which is restricted for working capital needs of Nicor Gas.

As reflected in the table above, in May 2017, Southern Company, Alabama Power, Georgia Power, and Southern Power Company each amended certain of their multi-year credit arrangements, which, among other things, extended the maturity dates from 2020 to 2022. Southern Company and Southern Power Company increased their borrowing ability under these arrangements to $2.0 billion from $1.25 billion and to $750 million from $600 million , respectively. Southern Company also terminated its $1.0 billion facility maturing in 2018. Also in May 2017, Southern Company Gas Capital and Nicor Gas terminated their existing credit arrangements for $1.3 billion and $700 million , respectively, which were to mature in 2017 and 2018, and entered into a new multi-year credit arrangement currently allocated for $1.2 billion and $700 million , respectively, with a maturity date of 2022.

Subject to applicable market conditions, Southern Company and its subsidiaries expect to renew or replace their bank credit arrangements as needed, prior to expiration. In connection therewith, Southern Company and its subsidiaries may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

Financing Activities

The following table outlines the long-term debt financing activities for Southern Company and its subsidiaries for the first six months of 2017 :

Company	Senior Note Issuances	Senior Note Maturities and Redemptions	Revenue Bond Maturities, Redemptions, and Repurchases	Other Long-Term Debt Issuances	Other Long-Term Debt Redemptions and Maturities [(a)]
			(in millions)		
Southern Company [(b)]	$ 300	$ —	$ —	$ 500	$ 400
Alabama Power	550	200	—	—	—
Georgia Power	850	450	27	—	3
Gulf Power	300	85	—	6	—
Mississippi Power	—	—	—	40	893
Southern Power	—	—	—	3	3
Southern Company Gas [(c)]	450	—	—	—	—
Other	—	—	—	—	8
Elimination [(d)]	—	—	—	(40)	(591)
Southern Company Consolidated	$ 2,450	$ 735	$ 27	$ 509	$ 716

(a) Includes reductions in capital lease obligations resulting from cash payments under capital leases.

(b) Represents the Southern Company parent entity.

(c) The senior notes were issued by Southern Company Gas Capital and guaranteed by the Southern Company Gas parent entity.

(d) Intercompany loans from Southern Company to Mississippi Power eliminated in Southern Company's Consolidated Financial Statements.

Southern Company

In June 2017, Southern Company issued $500 million aggregate principal amount of Series 2017A 5.325% Junior Subordinated Notes due June 21, 2057. The proceeds were used to repay short-term indebtedness and for other general corporate purposes.

Also in June 2017, Southern Company issued $300 million aggregate principal amount of Series 2017A Floating Rate Senior Notes due September 30, 2020, which bear interest at a floating rate based on three -month LIBOR. The proceeds were used to repay short-term indebtedness and for other general corporate purposes.

Also in June 2017, Southern Company entered into two $100 million aggregate principal amount floating rate bank term loan agreements, which mature on June 21, 2018 and June 29, 2018 and bear interest based on one -month LIBOR. The proceeds were used for working capital and other general corporate purposes.

Alabama Power

In March 2017, Alabama Power issued $550 million aggregate principal amount of Series 2017A 2.45% Senior Notes due March 30, 2022. The proceeds were used to repay Alabama Power's short-term indebtedness and for general corporate purposes, including Alabama Power's continuous construction program.

Georgia Power

In March 2017, Georgia Power issued $450 million aggregate principal amount of Series 2017A 2.00% Senior Notes due March 30, 2020 and $400 million aggregate principal amount of Series 2017B 3.25% Senior Notes due March 30, 2027. The proceeds were used to repay a portion of Georgia Power's short-term indebtedness and for general corporate purposes, including Georgia Power's continuous construction program.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
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In April 2017, Georgia Power purchased and held $27 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Fifth Series 1995. Georgia Power may reoffer these bonds to the public at a later date.

In June 2017, Georgia Power entered into three floating rate bank loans in aggregate principal amounts of $50 million , $150 million , and $100 million , which mature on December 1, 2017, May 31, 2018, and June 28, 2018, respectively, and bear interest based on one -month LIBOR. Also in June 2017, Georgia Power borrowed $500 million pursuant to an uncommitted bank credit arrangement, which bears interest at a rate agreed upon by Georgia Power and the bank from time to time and is payable on no less than 30 days' demand by the bank. The proceeds from these bank loans were used to repay a portion of Georgia Power's existing indebtedness and for working capital and other general corporate purposes, including Georgia Power's continuous construction program.

Gulf Power

In March 2017, Gulf Power extended the maturity of a $100 million short-term floating rate bank loan bearing interest based on one -month LIBOR from April 2017 to October 2017 and subsequently repaid the loan in May 2017.

In May 2017, Gulf Power issued $300 million aggregate principal amount of Series 2017A 3.30% Senior Notes due May 30, 2027. The proceeds, together with other funds, were used to repay at maturity $85 million aggregate principal amount of Series 2007A 5.90% Senior Notes due June 15, 2017; to repay outstanding commercial paper borrowings; to repay a $100 million short-term floating rate bank loan, as discussed above; and to redeem 550,000 shares ($55 million aggregate liquidation amount) of Gulf Power's 6.00% Series Preference Stock, 450,000 shares ($45 million aggregate liquidation amount) of Gulf Power's Series 2007A 6.45% Preference Stock, and 500,000 shares ($50 million aggregate liquidation amount) of Gulf Power's Series 2013A 5.60% Preference Stock.

Mississippi Power

In March 2017, Mississippi Power issued a $9 million short-term bank note bearing interest at 5% per annum, which was repaid in April 2017.

In February 2017, Mississippi Power amended $551 million in promissory notes to Southern Company extending the maturity dates of the notes from December 1, 2017 to July 31, 2018. In the second quarter 2017, Mississippi Power borrowed an additional $40 million under a promissory note issued to Southern Company.

In June 2017, Southern Company made equity contributions totaling $1.0 billion to Mississippi Power. Mississippi Power used a portion of the proceeds to (i) prepay $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan, which matures on March 30, 2018; (ii) repay all of the $591 million outstanding principal amount of promissory notes to Southern Company; and (iii) repay a $10 million short-term bank loan.

Southern Company Gas

In May 2017, Southern Company Gas Capital issued $450 million aggregate principal amount of Series 2017A 4.40% Senior Notes due May 30, 2047. The proceeds were used to repay Southern Company Gas' short-term indebtedness and for general corporate purposes.

(F) RETIREMENT BENEFITS

Southern Company has a defined benefit, trusteed, pension plan covering substantially all employees, with the exception of employees at Southern Company Gas, as discussed below, and PowerSecure. The Southern Company qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No mandatory contributions to the Southern Company qualified pension plan are anticipated for the year ending December 31, 2017 . Southern Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, Southern Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The traditional electric

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
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operating companies fund related other postretirement trusts to the extent required by their respective regulatory commissions.

In addition, Southern Company Gas has a qualified defined benefit, trusteed, pension plan covering certain eligible employees, which was closed in 2012 to new employees. This qualified pension plan is funded in accordance with requirements of ERISA. No mandatory contributions to the Southern Company Gas qualified pension plan are anticipated for the year ending December 31, 2017 . Southern Company Gas also provides certain non-qualified defined benefit and defined contribution pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, Southern Company Gas provides certain medical care and life insurance benefits for eligible retired employees through a postretirement benefit plan. Southern Company Gas also has a separate unfunded supplemental retirement health care plan that provides medical care and life insurance benefits to employees of discontinued businesses.

See Note 2 to the financial statements of Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Company Gas in Item 8 of the Form 10-K for additional information.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

Components of the net periodic benefit costs for the three and six months ended June 30, 2017 and 2016 are presented in the following tables.

Pension Plans	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power
			(in millions)		
Three Months Ended June 30, 2017					
Service cost	$ 74	$ 16	$ 18	$ 4	$ 3
Interest cost	113	24	35	5	5
Expected return on plan assets	(225)	(49)	(70)	(9)	(10)
Amortization:					
Prior service costs	3	—	1	—	1
Net (gain)/loss	41	11	14	1	2
Net periodic pension cost (income)	$ 6	$ 2	$ (2)	$ 1	$ 1
Six Months Ended June 30, 2017					
Service cost	$ 147	$ 32	$ 37	$ 7	$ 7
Interest cost	227	48	69	10	10
Expected return on plan assets	(449)	(98)	(141)	(19)	(20)
Amortization:					
Prior service costs	6	1	2	—	1
Net (gain)/loss	81	21	28	3	4
Net periodic pension cost (income)	$ 12	$ 4	$ (5)	$ 1	$ 2
Three Months Ended June 30, 2016					
Service cost	$ 62	$ 15	$ 18	$ 3	$ 3
Interest cost	101	24	34	4	5
Expected return on plan assets	(187)	(46)	(65)	(8)	(8)
Amortization:					
Prior service costs	3	—	2	1	—
Net (gain)/loss	37	10	13	1	1
Net periodic pension cost	$ 16	$ 3	$ 2	$ 1	$ 1
Six Months Ended June 30, 2016					
Service cost	$ 124	$ 29	$ 35	$ 6	$ 6
Interest cost	201	48	68	9	10
Expected return on plan assets	(374)	(92)	(129)	(17)	(17)
Amortization:					
Prior service costs	7	1	3	1	—
Net (gain)/loss	75	20	27	3	3
Net periodic pension cost	$ 33	$ 6	$ 4	$ 2	$ 2

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

Pension Plans		Southern Company Gas
		(in millions)
Successor – Three Months Ended June 30, 2017		
Service cost	$	5
Interest cost		10
Expected return on plan assets		(17)
Amortization:		
Prior service costs		(1)
Net (gain)/loss		5
Net periodic pension cost	$	2
Successor – Six Months Ended June 30, 2017		
Service cost	$	11
Interest cost		20
Expected return on plan assets		(35)
Amortization:		
Prior service costs		(1)
Net (gain)/loss		10
Net periodic pension cost	$	5
Predecessor – Three Months Ended June 30, 2016		
Service cost	$	7
Interest cost		11
Expected return on plan assets		(17)
Amortization:		
Prior service costs		(1)
Net (gain)/loss		7
Net periodic pension cost	$	7
Predecessor – Six Months Ended June 30, 2016		
Service cost	$	13
Interest cost		21
Expected return on plan assets		(33)
Amortization:		
Prior service costs		(1)
Net (gain)/loss		13
Net periodic pension cost	$	13

Postretirement Benefits	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power
			(in millions)		
Three Months Ended June 30, 2017					
Service cost	$ 6	$ 2	$ 1	$ 1	$ 1
Interest cost	20	4	8	—	1
Expected return on plan assets	(17)	(8)	(6)	(1)	(1)
Amortization:					
Prior service costs	1	1	1	—	—
Net (gain)/loss	5	1	1	—	—
Net periodic postretirement benefit cost	$ 15	$ —	$ 5	$ —	$ 1
Six Months Ended June 30, 2017					
Service cost	$ 12	$ 3	$ 3	$ 1	$ 1
Interest cost	40	9	15	1	2
Expected return on plan assets	(33)	(14)	(12)	(1)	(1)
Amortization:					
Prior service costs	3	2	1	—	—
Net (gain)/loss	7	1	3	—	—
Net periodic postretirement benefit cost	$ 29	$ 1	$ 10	$ 1	$ 2
Three Months Ended June 30, 2016					
Service cost	$ 6	$ 2	$ 1	$ 1	$ 1
Interest cost	17	4	7	—	1
Expected return on plan assets	(14)	(7)	(5)	(1)	(1)
Amortization:					
Prior service costs	1	1	1	—	—
Net (gain)/loss	4	1	2	—	—
Net periodic postretirement benefit cost	$ 14	$ 1	$ 6	$ —	$ 1
Six Months Ended June 30, 2016					
Service cost	$ 11	$ 3	$ 3	$ 1	$ 1
Interest cost	35	9	15	1	2
Expected return on plan assets	(28)	(13)	(11)	(1)	(1)
Amortization:					
Prior service costs	3	2	1	—	—
Net (gain)/loss	7	1	4	—	—
Net periodic postretirement benefit cost	$ 28	$ 2	$ 12	$ 1	$ 2

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

Postretirement Benefits	Southern Company Gas
	(in millions)
Successor – Three Months Ended June 30, 2017	
Service cost	$ —
Interest cost	2
Expected return on plan assets	(1)
Amortization:	
Prior service costs	—
Net (gain)/loss	1
Net periodic postretirement benefit cost	$ 2
Successor – Six Months Ended June 30, 2017	
Service cost	$ 1
Interest cost	5
Expected return on plan assets	(3)
Amortization:	
Prior service costs	(1)
Net (gain)/loss	2
Net periodic postretirement benefit cost	$ 4
Predecessor – Three Months Ended June 30, 2016	
Service cost	$ —
Interest cost	2
Expected return on plan assets	(1)
Amortization:	
Prior service costs	—
Net (gain)/loss	1
Net periodic postretirement benefit cost	$ 2
Predecessor – Six Months Ended June 30, 2016	
Service cost	$ 1
Interest cost	5
Expected return on plan assets	(3)
Amortization:	
Prior service costs	(1)
Net (gain)/loss	2
Net periodic postretirement benefit cost	$ 4

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
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(G) INCOME TAXES

See Note 5 to the financial statements of each registrant in Item 8 of the Form 10-K for additional tax information.

Current and Deferred Income Taxes

Tax Credit Carryforwards

Southern Company had federal ITC and PTC carryforwards (primarily related to Southern Power) totaling $1.9 billion as of June 30, 2017 compared to $1.8 billion as of December 31, 2016 .

The federal ITC carryforwards begin expiring in 2032 but are expected to be fully utilized by 2022. The PTC carryforwards begin expiring in 2036 but are expected to be utilized by 2022. The expected utilization of tax credit carryforwards could be further delayed by numerous factors. These factors include the acquisition of additional renewable projects, increased generation at existing wind facilities, carrying back the federal net operating loss, and potential tax reform legislation, as well as additional deductions in the event of an asset abandonment. The ultimate outcome of these matters cannot be determined at this time.

Valuation Allowances

At June 30, 2017 , valuation allowances were as follows:

	Mississippi Power	Southern Company Gas	Southern Company
		(in millions)	
Federal	$ —	$ 18	$ 18
State (net of federal benefit)	46	1	63
Balance at June 30, 2017	$ 46	$ 19	$ 81

Southern Company had valuation allowances, net of the federal benefit, of $81 million at June 30, 2017 compared to $21 million at December 31, 2016. The increase was primarily due to Mississippi Power's projected inability to utilize the State of Mississippi net operating loss.

Effective Tax Rate

Southern Company

Southern Company's effective tax rate is typically lower than the statutory rate due to employee stock plans' dividend deduction, non-taxable AFUDC equity, and federal income tax benefits from ITCs and PTCs.

Southern Company's effective tax (benefit) rate was (28.6)% for the six months ended June 30, 2017 compared to 29.4% for the corresponding period in 2016 . The effective tax rate decrease was primarily due to the estimated probable losses on the Kemper IGCC, net of the non-deductible AFUDC equity portion. Other factors include an increase in tax benefits from wind PTCs and state apportionment rate changes, partially offset by a decrease in tax benefits from ITCs and an increase in state valuation allowances.

Southern Company recognizes PTCs when wind energy is generated and sold (using the prescribed KWH rate in applicable federal and state statutes), which may differ significantly from amounts computed on a quarterly basis using an overall estimated annual effective income tax rate. Southern Company uses this method of recognition since the amount of PTCs can be significantly impacted by wind generation. This method can significantly affect the effective income tax rate for the period depending on the amount of pretax income.

Mississippi Power

Mississippi Power's effective tax (benefit) rate was (30.5)% for the six months ended June 30, 2017 compared to (208.1)% for the corresponding period in 2016 . The effective tax rate increase was primarily due to the estimated

probable losses on the Kemper IGCC, net of the non-deductible AFUDC equity portion and the related state valuation allowances.

Southern Power

Southern Power's effective tax (benefit) rate was (114.7)% for the six months ended June 30, 2017 compared to (74.0)% for the corresponding period in 2016 . The effective tax rate decrease was primarily due to additional PTCs arising from Southern Power's wind facility acquisitions, state apportionment rate changes, and lower pre-tax earnings, partially offset by a decrease in tax benefits from ITCs.

Southern Power recognizes PTCs when wind energy is generated and sold (using the prescribed KWH rate in applicable federal and state statutes), which may differ significantly from amounts computed on a quarterly basis using an overall estimated annual effective income tax rate. Southern Power uses this method of recognition since the amount of PTCs can be significantly impacted by wind generation. This method can significantly affect the effective income tax rate for the period depending on the amount of pretax income.

Unrecognized Tax Benefits

See Note 5 to the financial statements of each registrant under "Unrecognized Tax Benefits" in Item 8 of the Form 10-K for additional information.

Changes during the six months ended June 30, 2017 for unrecognized tax benefits were as follows:

	Mississippi Power	Southern Power	Southern Company
		(in millions)	
Unrecognized tax benefits as of December 31, 2016	$ 465	$ 17	$ 484
Tax positions from current periods	3	1	10
Tax positions from prior periods	—	1	7
Balance as of June 30, 2017	$ 468	$ 19	$ 501

The tax positions from current and prior periods primarily relate to state tax benefits and charitable contribution carryforwards that will be impacted as a result of the proposed settlement of R&E expenditures associated with the Kemper IGCC. See " Section 174 Research and Experimental Deduction " herein for additional information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

The impact on the effective tax rate, if recognized, is as follows:

	As of June 30, 2017			As of December 31, 2016
	Mississippi Power	Southern Power	Southern Company	Southern Company
			(in millions)	
Tax positions impacting the effective tax rate	**$ 4**	**$ 19**	**$ 37**	$ 20
Tax positions not impacting the effective tax rate	**464**	**—**	**464**	464
Balance of unrecognized tax benefits	**$ 468**	**$ 19**	**$ 501**	$ 484

The tax positions impacting the effective tax rate primarily relate to federal deferred income tax credits and Southern Company's estimate of the uncertainty related to the amount of those benefits, and state tax benefits and charitable contribution carryforwards that will be impacted as a result of the proposed settlement of R&E expenditures associated with the Kemper IGCC. See " Section 174 Research and Experimental Deduction " herein for additional information. If these tax positions are not able to be recognized due to a federal audit adjustment in

the amount that has been estimated, the amount of tax credit carryforwards discussed above would be reduced by approximately $98 million .

Accrued interest for all tax positions other than the Section 174 R&E deductions was immaterial for all periods presented.

All of the registrants classify interest on tax uncertainties as interest expense. None of the registrants accrued any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months . The settlement of federal and state audits and the U.S. Congress Joint Committee on Taxation approval of the R&E expenditures associated with the Kemper IGCC could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined. See " Section 174 Research and Experimental Deduction " herein for more information.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013, 2014, and 2015 federal income tax returns and has received partial acceptance letters from the IRS; however, the IRS has not finalized its audits. Southern Company is a participant in the Compliance Assurance Process of the IRS. In addition, the pre-Merger Southern Company Gas 2014 federal tax return is currently under audit. The audits for Southern Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

Section 174 Research and Experimental Deduction

Southern Company reflected deductions for R&E expenditures related to the Kemper IGCC in its federal income tax calculations since 2013 and filed amended federal income tax returns for 2008 through 2013 to also include such deductions.

The Kemper IGCC is based on first-of-a-kind technology, and Southern Company and Mississippi Power believe that a significant portion of the plant costs qualify as deductible R&E expenditures under IRC Section 174. In December 2016, Southern Company and the IRS reached a proposed settlement, subject to approval of the U.S. Congress Joint Committee on Taxation, resolving a methodology for these deductions. Due to the uncertainty related to this tax position, Southern Company and Mississippi Power had unrecognized tax benefits associated with these R&E deductions totaling approximately $464 million and associated interest of $36 million as of June 30, 2017 . If the suspension of the Kemper IGCC start-up activities results in an abandonment, any amount not allowed under IRC Section 174 would be claimed as a deduction under IRC Section 165, and would result in a reversal of the related unrecognized tax benefits, excluding interest. The ultimate outcome of this matter cannot be determined at this time.

(H) DERIVATIVES

Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas are exposed to market risks, including commodity price risk, interest rate risk, weather risk, and occasionally foreign currency exchange rate risk. To manage the volatility attributable to these exposures, each company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to each company's policies in areas such as counterparty exposure and risk management practices. Southern Company Gas' wholesale gas operations use various contracts in its commercial activities that generally meet the definition of derivatives. For the traditional electric operating companies, Southern Power, and Southern Company Gas' other businesses, each company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net basis. See Note (C) 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. The cash

impacts of settled foreign currency derivatives are classified as operating or financing activities to correspond with classification of the hedged interest or principal, respectively.

Energy-Related Derivatives

Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas enter into energy-related derivatives to hedge exposures to electricity, natural gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the traditional electric operating companies and the natural gas distribution utilities have limited exposure to market volatility in energy-related commodity prices. Each of the traditional electric operating companies and certain of the natural gas distribution utilities of Southern Company Gas manage fuel-hedging programs, implemented per the guidelines of their respective state PSCs or other applicable state regulatory agencies, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. The Florida PSC extended the moratorium on Gulf Power's fuel-hedging program through January 1, 2021 in connection with the 2017 Rate Case Settlement Agreement. The moratorium does not have an impact on the recovery of existing hedges entered into under the previously-approved hedging program. The traditional electric operating companies (with respect to wholesale generating capacity) and Southern Power have limited exposure to market volatility in energy-related commodity prices because their long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, the traditional electric operating companies and Southern Power may be exposed to market volatility in energy-related commodity prices to the extent any uncontracted capacity is used to sell electricity. Southern Company Gas retains exposure to price changes that can, in a volatile energy market, be material and can adversely affect its results of operations.

Southern Company Gas also enters into weather derivative contracts as economic hedges of operating margins in the event of warmer-than-normal weather. Exchange-traded options are carried at fair value, with changes reflected in operating revenues. Non exchange-traded options are accounted for using the intrinsic value method. Changes in the intrinsic value for non-exchange-traded contracts are reflected in the statements of income.

Energy-related derivative contracts are accounted for under one of three methods:

- *Regulatory Hedges* — Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the traditional electric operating companies' and the natural gas distribution utilities' fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the respective fuel cost recovery clauses.
- *Cash Flow Hedges* — Gains and losses on energy-related derivatives designated as cash flow hedges (which are mainly used to hedge anticipated purchases and sales) are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* — Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric and natural gas industries. 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.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

At June 30, 2017 , the net volume of energy-related derivative contracts for natural gas positions for the Southern Company system, together with the longest hedge date over which the respective entity is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest non-hedge date for derivatives not designated as hedges, were as follows:

	Net Purchased mmBtu	Longest Hedge Date	Longest Non-Hedge Date
	(in millions)		
Southern Company (*)	472	2021	2024
Alabama Power	70	2020	—
Georgia Power	160	2020	—
Gulf Power	35	2020	—
Mississippi Power	41	2021	—
Southern Power	25	2017	—
Southern Company Gas (*)	141	2019	2024

(*) Southern Company's and Southern Company Gas' derivative instruments include both long and short natural gas positions. A long position is a contract to purchase natural gas and a short position is a contract to sell natural gas. Southern Company Gas' volume represents the net of long natural gas positions of 3.5 billion mmBtu and short natural gas positions of 3.4 billion mmBtu as of June 30, 2017 , which is also included in Southern Company's total volume.

In addition to the volumes discussed above, the traditional electric operating companies and Southern Power enter into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 31 million mmBtu for Southern Company, 10 million mmbtu for Georgia Power and Southern Power, 5 million mmbtu for Alabama Power, and 3 million mmBtu for Gulf Power and Mississippi Power.

For cash flow hedges of energy-related derivatives, the amounts expected to be reclassified from accumulated OCI to earnings for the next 12 -month period ending June 30, 2018 are $6 million for Southern Power and immaterial for all other registrants.

Interest Rate Derivatives

Southern Company and certain subsidiaries may also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings, with any ineffectiveness recorded directly to earnings. Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value gains or losses are both recorded directly to earnings, providing an offset, with any difference representing ineffectiveness. Fair value gains or losses on derivatives that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

At June 30, 2017 , the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) at June 30, 2017
	(in millions)				*(in millions)*
Cash Flow Hedges of Existing Debt					
Mississippi Power	$ 900	1-month LIBOR	0.79%	March 2018	$ 3
Fair Value Hedges of Existing Debt					
Southern Company (*)	250	1.30%	3-month LIBOR + 0.17%	August 2017	—
Southern Company (*)	300	2.75%	3-month LIBOR + 0.92%	June 2020	1
Southern Company (*)	1,500	2.35%	1-month LIBOR + 0.87%	July 2021	(14)
Georgia Power	250	5.40%	3-month LIBOR + 4.02%	June 2018	—
Georgia Power	500	1.95%	3-month LIBOR + 0.76%	December 2018	(2)
Georgia Power	200	4.25%	3-month LIBOR + 2.46%	December 2019	1
Southern Company Consolidated	$ 3,900				$ (11)

(*) Represents the Southern Company parent entity.

The estimated pre-tax gains (losses) related to interest rate derivatives expected to be reclassified from accumulated OCI to interest expense for the next 12 -month period ending June 30, 2018 are $(21) million for Southern Company and immaterial for all other registrants. Southern Company and certain subsidiaries have deferred gains and losses expected to be amortized into earnings through 2046 .

Foreign Currency Derivatives

Southern Company and certain subsidiaries may also enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates, such as that arising from the issuance of debt denominated in a currency other than U.S. dollars. Derivatives related to 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 that the hedged transactions affect earnings, including foreign currency gains or losses arising from changes in the U.S. currency exchange rates. Any ineffectiveness is recorded directly to earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

At June 30, 2017 , the following foreign currency derivatives were outstanding:

	Pay Notional	Pay Rate	Receive Notional	Receive Rate	Hedge Maturity Date	Fair Value Gain (Loss) at June 30, 2017
	(in millions)		*(in millions)*			*(in millions)*
Cash Flow Hedges of Existing Debt						
Southern Power	$ 677	2.95%	€ 600	1.00%	June 2022	$ 18
Southern Power	564	3.78%	500	1.85%	June 2026	15
Total	$ 1,241		€ 1,100			$ 33

The estimated pre-tax gains (losses) related to foreign currency derivatives that will be reclassified from accumulated OCI to earnings for the next 12 -month period ending June 30, 2018 are $(23) million for Southern Company and Southern Power.

Derivative Financial Statement Presentation and Amounts

Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas enter into derivative contracts that may contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Southern Company and certain subsidiaries also utilize master netting agreements to mitigate exposure to counterparty credit risk. These agreements may contain provisions that permit netting across product lines and against cash collateral. The fair value amounts of derivative assets and liabilities on the balance sheet are presented net to the extent that there are netting arrangements or similar agreements with the counterparties.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

The fair value of energy-related derivatives, interest rate derivatives, and foreign currency derivatives was reflected in the balance sheets as follows:

	As of June 30, 2017		As of December 31, 2016	
Derivative Category and Balance Sheet Location	**Assets**	**Liabilities**	**Assets**	**Liabilities**
	(in millions)		*(in millions)*	
Southern Company				
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Liabilities from risk management activities, net of collateral	$ 23	$ 35	$ 73	$ 27
Other deferred charges and assets/Other deferred credits and liabilities	8	31	25	33
Total derivatives designated as hedging instruments for regulatory purposes	$ 31	$ 66	$ 98	$ 60
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Energy-related derivatives:				
Other current assets/Liabilities from risk management activities, net of collateral	$ 13	$ 10	$ 23	$ 7
Interest rate derivatives:				
Other current assets/Liabilities from risk management activities, net of collateral	11	1	12	1
Other deferred charges and assets/Other deferred credits and liabilities	—	22	1	28
Foreign currency derivatives:				
Other current assets/Liabilities from risk management activities, net of collateral	—	23	—	25
Other deferred charges and assets/Other deferred credits and liabilities	56	—	—	33
Total derivatives designated as hedging instruments in cash flow and fair value hedges	$ 80	$ 56	$ 36	$ 94
Derivatives not designated as hedging instruments				
Energy-related derivatives:				
Other current assets/Liabilities from risk management activities, net of collateral	$ 237	$ 202	$ 489	$ 483
Other deferred charges and assets/Other deferred credits and liabilities	102	86	66	81
Interest rate derivatives:				
Other current assets/Liabilities from risk management activities, net of collateral	—	—	1	—
Total derivatives not designated as hedging instruments	$ 339	$ 288	$ 556	$ 564
Gross amounts recognized	$ 450	$ 410	$ 690	$ 718
Gross amounts offset (*)	$ (219)	$ (290)	$ (462)	$ (524)
Net amounts recognized in the Balance Sheets	$ 231	$ 120	$ 228	$ 194

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

	As of June 30, 2017		As of December 31, 2016	
Derivative Category and Balance Sheet Location	**Assets**	**Liabilities**	**Assets**	**Liabilities**
	(in millions)		*(in millions)*	
Alabama Power				
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Liabilities from risk management activities	$ 7	$ 7	$ 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	$ 9	$ 11	$ 20	$ 9
Gross amounts recognized	$ 9	$ 11	$ 20	$ 9
Gross amounts offset	$ (6)	$ (6)	$ (8)	$ (8)
Net amounts recognized in the Balance Sheets	$ 3	$ 5	$ 12	$ 1
Georgia Power				
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Other current liabilities	$ 10	$ 4	$ 30	$ 1
Other deferred charges and assets/Other deferred credits and liabilities	5	10	14	7
Total derivatives designated as hedging instruments for regulatory purposes	$ 15	$ 14	$ 44	$ 8
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Interest rate derivatives:				
Other current assets/Other current liabilities	$ 1	$ 1	$ 2	$ —
Other deferred charges and assets/Other deferred credits and liabilities	—	2	—	3
Total derivatives designated as hedging instruments in cash flow and fair value hedges	$ 1	$ 3	$ 2	$ 3
Gross amounts recognized	$ 16	$ 17	$ 46	$ 11
Gross amounts offset	$ (9)	$ (9)	$ (8)	$ (8)
Net amounts recognized in the Balance Sheets	$ 7	$ 8	$ 38	$ 3
Gulf Power				
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Liabilities from risk management activities	$ 1	$ 16	$ 4	$ 12
Other deferred charges and assets/Other deferred credits and liabilities	—	13	1	17
Total derivatives designated as hedging instruments for regulatory purposes	$ 1	$ 29	$ 5	$ 29
Gross amounts recognized	$ 1	$ 29	$ 5	$ 29
Gross amounts offset	$ (1)	$ (1)	$ (4)	$ (4)
Net amounts recognized in the Balance Sheets	$ —	$ 28	$ 1	$ 25

**NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)**

	As of June 30, 2017		As of December 31, 2016	
Derivative Category and Balance Sheet Location	**Assets**	**Liabilities**	**Assets**	**Liabilities**
	(in millions)		*(in millions)*	
Mississippi Power				
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Other current liabilities	$ 1	$ 6	$ 2	$ 6
Other deferred charges and assets/Other deferred credits and liabilities	1	4	2	5
Total derivatives designated as hedging instruments for regulatory purposes	$ 2	$ 10	$ 4	$ 11
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Interest rate derivatives:				
Other current assets/Other current liabilities	$ 3	$ —	$ 2	$ —
Other deferred charges and assets/Other deferred credits and liabilities	—	—	1	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges	$ 3	$ —	$ 3	$ —
Gross amounts recognized	$ 5	$ 10	$ 7	$ 11
Gross amounts offset	$ (2)	$ (2)	$ (3)	$ (3)
Net amounts recognized in the Balance Sheets	$ 3	$ 8	$ 4	$ 8
Southern Power				
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Energy-related derivatives:				
Other current assets/Other current liabilities	$ 13	$ 8	$ 18	$ 4
Foreign currency derivatives:				
Other current assets/Other current liabilities	—	23	—	25
Other deferred charges and assets/Other deferred credits and liabilities	56	—	—	33
Total derivatives designated as hedging instruments in cash flow and fair value hedges	$ 69	$ 31	$ 18	$ 62
Derivatives not designated as hedging instruments				
Energy-related derivatives:				
Other current assets/Other current liabilities	$ 1	$ 1	$ 3	$ 1
Interest rate derivatives:				
Other current assets/Other current liabilities	—	—	1	—
Total derivatives not designated as hedging instruments	$ 1	$ 1	$ 4	$ 1
Gross amounts recognized	$ 70	$ 32	$ 22	$ 63
Gross amounts offset	$ (2)	$ (2)	$ (5)	$ (5)
Net amounts recognized in the Balance Sheets	$ 68	$ 30	$ 17	$ 58

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

	As of June 30, 2017		As of December 31, 2016	
Derivative Category and Balance Sheet Location	**Assets**	**Liabilities**	**Assets**	**Liabilities**
	(in millions)		*(in millions)*	
Southern Company Gas				
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Assets from risk management activities/Liabilities from risk management activities-current	$ 4	$ 2	$ 24	$ 3
Other deferred charges and assets/Other deferred credits and liabilities	—	—	1	—
Total derivatives designated as hedging instruments for regulatory purposes	$ 4	$ 2	$ 25	$ 3
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Energy-related derivatives:				
Assets from risk management activities/Liabilities from risk management activities-current	$ —	$ 2	$ 4	$ 3
Derivatives not designated as hedging instruments				
Energy-related derivatives:				
Assets from risk management activities/Liabilities from risk management activities-current	$ 236	$ 201	$ 486	$ 482
Other deferred charges and assets/Other deferred credits and liabilities	102	86	66	81
Total derivatives not designated as hedging instruments	$ 338	$ 287	$ 552	$ 563
Gross amounts of recognized	$ 342	$ 291	$ 581	$ 569
Gross amounts offset (*)	$ (196)	$ (267)	$ (435)	$ (497)
Net amounts recognized in the Balance Sheets	$ 146	$ 24	$ 146	$ 72

(*) Gross amounts offset include cash collateral held on deposit in broker margin accounts of $71 million and $62 million as of June 30, 2017 and December 31, 2016 , respectively.

At June 30, 2017 and December 31, 2016 , the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred were as follows:

Regulatory Hedge Unrealized Gain (Loss) Recognized in the Balance Sheet at June 30, 2017

Derivative Category and Balance Sheet Location	**Southern Company** (b)	**Alabama Power**	**Georgia Power**	**Gulf Power**	**Mississippi Power**	**Southern Company Gas** (b)
			(in millions)			
Energy-related derivatives:						
Other regulatory assets, current	$ (24)	$ (3)	$ —	$ (15)	$ (5)	$ (1)
Other regulatory assets, deferred	(23)	(2)	(5)	(13)	(3)	—
Other regulatory liabilities, current (a)	13	3	6	—	—	4
Total energy-related derivative gains (losses)	$ (34)	$ (2)	$ 1	$ (28)	$ (8)	$ 3

(a) Georgia Power includes other regulatory liabilities, current in other current liabilities.

(b) Fair value gains and losses recorded in regulatory assets and liabilities include cash collateral held on deposit in broker margin accounts of $ 1 million at June 30, 2017 .

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

Regulatory Hedge Unrealized Gain (Loss) Recognized in the Balance Sheet at December 31, 2016						
Derivative Category and Balance Sheet Location	**Southern Company** [c]	**Alabama Power**	**Georgia Power**	**Gulf Power**	**Mississippi Power**	**Southern Company Gas** [c]
	(in millions)					
Energy-related derivatives:						
Other regulatory assets, current	$ (16)	$ (1)	$ —	$ (9)	$ (5)	$ (1)
Other regulatory assets, deferred	(19)	—	—	(16)	(3)	—
Other regulatory liabilities, current [a]	56	8	29	1	1	17
Other regulatory liabilities, deferred [b]	12	4	7	—	—	1
Total energy-related derivative gains (losses)	$ 33	$ 11	$ 36	$ (24)	$ (7)	$ 17

(a) Georgia Power includes other regulatory liabilities, current in other current liabilities.
(b) Georgia Power includes other regulatory liabilities, deferred in other deferred credits and liabilities.
(c) Fair value gains and losses recorded in regulatory assets and liabilities include cash collateral held on deposit in broker margin accounts of $ 8 million at December 31, 2016 .

For the three months ended June 30, 2017 and 2016 , the pre-tax effects of energy-related derivatives, interest rate derivatives, and foreign currency derivatives designated as cash flow hedging instruments were as follows:

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Recognized in OCI on Derivative (Effective Portion)**		**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**		
			Statements of Income Location	**Amount**	
	2017	2016		**2017**	2016
	(in millions)			*(in millions)*	
Southern Company					
Energy-related derivatives	**$ (9)**	$ —	Depreciation and amortization	**$ (2)**	$ —
Interest rate derivatives	**(1)**	6	Interest expense, net of amounts capitalized	**(5)**	(4)
Foreign currency derivatives	**71**	(39)	Interest expense, net of amounts capitalized	**(5)**	(1)
			Other income (expense), net [*]	**79**	(20)
Total	**$ 61**	$ (33)		**$ 67**	$ (25)
Alabama Power					
Interest rate derivatives	**$ —**	$ —	Interest expense, net of amounts capitalized	**$ (2)**	$ (2)
Georgia Power					
Interest rate derivatives	**$ —**	$ —	Interest expense, net of amounts capitalized	**$ (1)**	$ (1)
Gulf Power					
Interest rate derivatives	**$ (1)**	$ (2)	Interest expense, net of amounts capitalized	**$ —**	$ —
Southern Power					
Energy-related derivatives	**$ (7)**	$ —	Depreciation and amortization	**$ (2)**	$ —
Foreign currency derivatives	**71**	(39)	Interest expense, net of amounts capitalized	**(5)**	(1)
			Other income (expense), net [*]	**79**	(20)
Total	**$ 64**	$ (39)		**$ 72**	$ (21)

(*) The reclassification from accumulated OCI into other income (expense), net completely offsets currency gains and losses arising from changes in the U.S. currency exchange rates used to record the euro-denominated notes.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

For Southern Company Gas, the pre-tax effect of energy related derivatives and interest rate derivatives designated as cash flow hedging instruments recognized in OCI and those reclassified from accumulated OCI into earnings for the successor three months ended June 30, 2017 and the predecessor three months ended June 30, 2016 were as follows:

	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**	
	Successor	Predecessor		Successor	Predecessor
Derivatives in Cash Flow Hedging Relationships	**Three Months Ended June 30, 2017**	Three Months Ended June 30, 2016	**Statements of Income Location**	**Three Months Ended June 30, 2017**	Three Months Ended June 30, 2016
	(in millions)	*(in millions)*		*(in millions)*	*(in millions)*
Energy-related derivatives	**$ (2)**	$ —	Cost of natural gas	**$ —**	$ (1)
Interest rate derivatives	**—**	(19)	Interest expense, net of amounts capitalized	**—**	(1)
Total	**$ (2)**	$ (19)		**$ —**	$ (2)

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

For the six months ended June 30, 2017 and 2016 , the pre-tax effects of energy-related derivatives, interest rate derivatives, and foreign currency derivatives designated as cash flow hedging instruments were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)		Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)		
			Statements of Income Location	Amount	
	2017	2016		**2017**	2016
	(in millions)			*(in millions)*	
Southern Company					
Energy-related derivatives	**$ (20)**	$ —	Depreciation and amortization	**$ (6)**	$ —
Interest rate derivatives	**(1)**	(184)	Interest expense, net of amounts capitalized	**(10)**	(7)
Foreign currency derivatives	**67**	(39)	Interest expense, net of amounts capitalized	**(12)**	(1)
			Other income (expense), net (*)	**96**	(20)
Total	**$ 46**	$ (223)		**$ 68**	$ (28)
Alabama Power					
Interest rate derivatives	**$ —**	$ (4)	Interest expense, net of amounts capitalized	**$ (3)**	$ (3)
Georgia Power					
Interest rate derivatives	**$ —**	$ —	Interest expense, net of amounts capitalized	**$ (3)**	$ (2)
Gulf Power					
Energy-related derivatives	**$ (1)**	$ —	Depreciation and amortization	**$ —**	$ —
Interest rate derivatives	**(1)**	(7)	Interest expense, net of amounts capitalized	**—**	—
Total	**$ (2)**	$ (7)		**$ —**	$ —
Mississippi Power					
Interest rate derivatives	**$ —**	$ —	Interest expense, net of amounts capitalized	**$ (1)**	$ (1)
Southern Power					
Energy-related derivatives	**$ (15)**	$ —	Depreciation and amortization	**$ (6)**	$ —
Interest rate derivatives	**—**	—	Interest expense, net of amounts capitalized	**—**	(1)
Foreign currency derivatives	**67**	(39)	Interest expense, net of amounts capitalized	**(12)**	(1)
			Other income (expense), net (*)	**96**	(20)
Total	**$ 52**	$ (39)		**$ 78**	$ (22)

(*) The reclassification from accumulated OCI into other income (expense), net completely offsets currency gains and losses arising from changes in the U.S. currency exchange rates used to record the euro-denominated notes.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

For Southern Company Gas, the pre-tax effect of energy related derivatives and interest rate derivatives designated as cash flow hedging instruments recognized in OCI and those reclassified from accumulated OCI into earnings for the successor six months ended June 30, 2017 and the predecessor six months ended June 30, 2016 were as follows:

	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	
	Successor	Predecessor		Successor	Predecessor
Derivatives in Cash Flow Hedging Relationships	**Six Months Ended June 30, 2017**	Six Months Ended June 30, 2016	**Statements of Income Location**	**Six Months Ended June 30, 2017**	Six Months Ended June 30, 2016
	(in millions)	*(in millions)*		*(in millions)*	*(in millions)*
Energy-related derivatives	**$ (4)**	$ —	Cost of natural gas	**$ —**	$ (1)
Interest rate derivatives	**—**	(64)	Interest expense, net of amounts capitalized	**—**	—
Total	**$ (4)**	$ (64)		**$ —**	$ (1)

For the three and six months ended June 30, 2017 and 2016 , the pre-tax effects of energy-related derivatives and interest rate derivatives designated as cash flow hedging instruments were immaterial for the other registrants.

For the three and six months ended June 30, 2017 and 2016 , the pre-tax effects of energy-related derivatives and interest rate derivatives not designated as hedging instruments on the statements of income were as follows:

		Gain (Loss)			
		Three Months Ended June 30,		**Six Months Ended June 30,**	
Derivatives in Non-Designated Hedging Relationships	**Statements of Income Location**	**2017**	2016	**2017**	2016
		(in millions)		*(in millions)*	
Southern Company					
Energy Related derivatives:	Natural gas revenues [(*)]	**$ 16**	$ —	**$ 65**	$ —
	Cost of natural gas	**(2)**	—	**(4)**	—
Total derivatives in non-designated hedging relationships		**$ 14**	$ —	**$ 61**	$ —

(*) Excludes gains (losses) recorded in cost of natural gas associated with weather derivatives of $1 million and $15 million for the three and six months ended June 30, 2017 , respectively.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

		Gain (Loss)			
		Successor	Predecessor	**Successor**	Predecessor
Derivatives in Non-Designated Hedging Relationships	**Statements of Income Location**	**Three Months Ended June 30, 2017**	Three Months Ended June 30, 2016	**Six Months Ended June 30, 2017**	Six Months Ended June 30, 2016
		(in millions)	*(in millions)*	*(in millions)*	*(in millions)*
Southern Company Gas					
Energy Related derivatives:	Natural gas revenues [(*)]	**$ 16**	$ (21)	**$ 65**	$ (1)
	Cost of natural gas	**(2)**	(61)	**(4)**	(62)
Total derivatives in non-designated hedging relationships		**$ 14**	$ (82)	**$ 61**	$ (63)

(*) Excludes gains recorded in cost of natural gas associated with weather derivatives of $15 million for the successor six months ended June 30, 2017 and immaterial amounts for all other periods presented.

For the three and six months ended June 30, 2017 and 2016 , the pre-tax effects of energy-related derivatives and interest rate derivatives not designated as hedging instruments were immaterial for the traditional electric operating companies and Southern Power.

For the three and six months ended June 30, 2017 and 2016 , the pre-tax effects of interest rate derivatives designated as fair value hedging instruments were as follows:

Derivatives in Fair Value Hedging Relationships

		Gain (Loss)			
		Three Months Ended June 30,		**Six Months Ended June 30,**	
Derivative Category	**Statements of Income Location**	**2017**	2016	**2017**	2016
		(in millions)		*(in millions)*	
Southern Company					
Interest rate derivatives:	Interest expense, net of amounts capitalized	**$ 7**	$ 4	**$ (1)**	$ 24
Georgia Power					
Interest rate derivatives:	Interest expense, net of amounts capitalized	**$ —**	$ —	**$ (1)**	$ 15

For the three and six months ended June 30, 2017 and 2016 , the pre-tax effects of interest rate derivatives designated as fair value hedging instruments were offset by changes to the carrying value of long-term debt.

There was no material ineffectiveness recorded in earnings for any registrant for any period presented.

Contingent Features

Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain Southern Company subsidiaries. At June 30, 2017 , the registrants had no collateral posted with derivative counterparties to satisfy these arrangements.

At June 30, 2017 , the fair value of derivative liabilities with contingent features was immaterial for all registrants. The maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $11 million for Southern Company, $10 million for the traditional electric operating companies and Southern Power, and $1 million for Southern Company Gas. The maximum potential collateral

requirements arising from the credit-risk-related contingent features for the traditional electric operating companies and Southern Power include certain agreements that could require collateral in the event that one or more Southern Company 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.

Alabama Power and Southern Power maintain 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, Alabama Power and Southern Power may be required to post collateral. At June 30, 2017 , cash collateral posted in these accounts was immaterial. Southern Company Gas maintains accounts with brokers or the clearing houses of certain exchanges to facilitate financial derivative transactions. Based on the value of the positions in these accounts and the associated margin requirements, Southern Company Gas may be required to deposit cash into these accounts. At June 30, 2017 , cash collateral held on deposit in broker margin accounts was $71 million .

Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas are exposed to losses related to financial instruments in the event of counterparties' nonperformance. Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas only enter into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas have also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate Southern Company's, the traditional electric operating companies', Southern Power's, and Southern Company Gas' exposure to counterparty credit risk. Southern Company Gas may require counterparties to pledge additional collateral when deemed necessary.

In addition, Southern Company Gas conducts credit evaluations and obtains appropriate internal approvals for the counterparty's line of credit before any transaction with the counterparty is executed. In most cases, the counterparty must have an investment grade rating, which includes a minimum long-term debt rating of Baa3 from Moody's and BBB- from S&P. Generally, Southern Company Gas requires credit enhancements by way of a guaranty, cash deposit, or letter of credit for transaction counterparties that do not have investment grade ratings.

Southern Company Gas also utilizes master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When Southern Company Gas is engaged in more than one outstanding derivative transaction with the same counterparty and it also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of Southern Company Gas' credit risk. Southern Company Gas also uses other netting agreements with certain counterparties with whom it conducts significant transactions. Master netting agreements enable Southern Company Gas to net certain assets and liabilities by counterparty. Southern Company Gas also nets across product lines and against cash collateral provided the master netting and cash collateral agreements include such provisions. Southern Company Gas may require counterparties to pledge additional collateral when deemed necessary.

Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas do not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

(I) ACQUISITIONS

Southern Company

Merger with Southern Company Gas

Southern Company Gas is an energy services holding company whose primary business is the distribution of natural gas through the natural gas distribution utilities. On July 1, 2016, Southern Company completed the Merger for a total purchase price of approximately $8.0 billion and Southern Company Gas became a wholly-owned, direct subsidiary of Southern Company.

The Merger was accounted for using the acquisition method of accounting with the assets acquired and liabilities assumed recognized at fair value as of the acquisition date. The following table presents the final purchase price allocation:

Southern Company Gas Purchase Price

		(in millions)
Current assets	$	1,557
Property, plant, and equipment		10,108
Goodwill		5,967
Intangible assets		400
Regulatory assets		1,118
Other assets		229
Current liabilities		(2,201)
Other liabilities		(4,742)
Long-term debt		(4,261)
Noncontrolling interest		(174)
Total purchase price	$	8,001

The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed of $6.0 billion is recognized as goodwill, which is primarily attributable to positioning the Southern Company system to provide natural gas infrastructure to meet customers' growing energy needs and to compete for growth across the energy value chain. Southern Company anticipates that much of the value assigned to goodwill will not be deductible for tax purposes.

The valuation of identifiable intangible assets included customer relationships, trade names, and storage and transportation contracts with estimated lives of one to 28 years . The estimated fair value measurements of identifiable intangible assets were primarily based on significant unobservable inputs (Level 3).

The results of operations for Southern Company Gas have been included in Southern Company's consolidated financial statements from the date of acquisition and consist of operating revenues of $716 million and $2.3 billion and net income of $49 million and $288 million for the three and six months ended June 30, 2017 , respectively.

The following summarized unaudited pro forma consolidated statement of earnings information assumes that the acquisition of Southern Company Gas was completed on January 1, 2015. The summarized unaudited pro forma consolidated statement of earnings information includes adjustments for (i) intercompany sales, (ii) amortization of intangible assets, (iii) adjustments to interest expense to reflect current interest rates on Southern Company Gas debt and additional interest expense associated with borrowings by Southern Company to fund the Merger, and (iv) the elimination of nonrecurring expenses associated with the Merger.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

	For the Six Months Ended June 30,	
	2016	
Operating revenues *(in millions)*	$	10,346
Net income attributable to Southern Company *(in millions)*	$	1,255
Basic Earnings Per Share (EPS)	$	1.34
Diluted EPS	$	1.33

These unaudited pro forma results are for comparative purposes only and may not be indicative of the results that would have occurred had this acquisition been completed on January 1, 2015 or the results that would be attained in the future.

Acquisition of PowerSecure

On May 9, 2016, Southern Company acquired all of the outstanding stock of PowerSecure, a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure, for $18.75 per common share in cash, resulting in an aggregate purchase price of $429 million . As a result, PowerSecure became a wholly-owned subsidiary of Southern Company.

The acquisition of PowerSecure was accounted for using the acquisition method of accounting with the assets acquired and liabilities assumed recognized at fair value as of the acquisition date. The following table presents the final purchase price allocation:

PowerSecure Purchase Price		
	(in millions)	
Current assets	$	172
Property, plant, and equipment		46
Intangible assets		106
Goodwill		284
Other assets		4
Current liabilities		(121)
Long-term debt, including current portion		(48)
Deferred credits and other liabilities		(14)
Total purchase price	$	429

The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed of $284 million was recognized as goodwill, which is primarily attributable to expected business expansion opportunities for PowerSecure. Southern Company anticipates that the majority of the value assigned to goodwill will not be deductible for tax purposes.

The valuation of identifiable intangible assets included customer relationships, trade names, patents, backlog, and software with estimated lives of one to 26 years. The estimated fair value measurements of identifiable intangible assets were primarily based on significant unobservable inputs (Level 3).

The results of operations for PowerSecure have been included in Southern Company's consolidated financial statements from the date of acquisition and are immaterial to the consolidated financial results of Southern Company. Pro forma results of operations have not been presented for the acquisition because the effects of the acquisition were immaterial to Southern Company's consolidated financial results for all periods presented.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

Southern Power

See Note 2 to the financial statements of Southern Power and Note 12 to the financial statements of Southern Company under "Southern Power" in Item 8 of the Form 10-K for additional information.

Acquisitions During the Six Months Ended June 30, 2017

During the six months ended June 30, 2017, in accordance with Southern Power's overall growth strategy, Southern Renewable Partnerships, LLC (SRP), one of Southern Power's wholly-owned subsidiaries, acquired the Bethel wind facility . Acquisition-related costs were expensed as incurred and were not material.

Project Facility	Resource	Seller; Acquisition Date	Approximate Nameplate Capacity (*MW*)	Location	Southern Power Percentage Ownership	Actual COD	PPA Contract Period
Bethel	Wind	Invenergy, January 6, 2017	276	Castro County, TX	100%	January 2017	12 years

The aggregate amounts of revenue and net income, excluding impacts from PTCs, recognized by Southern Power related to the Bethel facility included in Southern Power's condensed consolidated statements of income for year-to-date 2017 were immaterial . The Bethel facility did not have operating revenues or activities prior to completion of construction and the assets being placed in service; therefore, supplemental pro forma information for the comparable 2016 period is not meaningful and has been omitted.

In connection with Southern Power's 2016 acquisitions, allocations of the purchase price to individual assets were finalized during the six months ended June 30, 2017 with no changes to amounts originally reported for Boulder 1, Grant Plains, Grant Wind, Henrietta, Mankato, Passadumkeag, Salt Fork, Tyler Bluff, and Wake Wind.

Acquisitions Subsequent to June 30, 2017

Subsequent to June 30, 2017, Southern Power acquired a 100% ownership interest in and commenced construction of the Cactus Flats 148 -MW wind facility, the majority of which is covered by two PPAs, which expire in 2030 and 2033. The facility is expected to be placed in service in mid-2018. The ultimate outcome of this matter cannot be determined at this time.

Construction Projects Completed and in Progress

During the six months ended June 30, 2017 , in accordance with its overall growth strategy, Southern Power completed construction of and placed in service, or continued construction of, the projects set forth in the following table. Through June 30, 2017 , total costs of construction incurred for these projects were $421 million , of which $49 million remained in CWIP for the Mankato facility acquired in 2016. Total aggregate construction costs, excluding the acquisition costs, are expected to be $170 million to $190 million for the Mankato facility. The ultimate outcome of this matter cannot be determined at this time.

Project Facility	Resource	Approximate Nameplate Capacity (*MW*)	Location	Actual/Expected COD	PPA Contract Period
Projects Completed During the Six Months Ended June 30, 2017					
East Pecos	Solar	120	Pecos County, TX	March 2017	15 years
Lamesa	Solar	102	Dawson County, TX	April 2017	15 years
Project Under Construction as of June 30, 2017					
Mankato	Natural Gas	345	Mankato, MN	Second quarter 2019	20 years

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

Development Projects

In December 2016, as part of Southern Power's renewable development strategy, SRP entered into a joint development agreement with Renewable Energy Systems Americas, Inc. to develop and construct approximately 3,000 MWs of wind projects. Also in December 2016, Southern Power signed agreements and made payments to purchase wind turbine equipment from Siemens Wind Power, Inc. and Vestas-American Wind Technology, Inc. to be used for construction of the facilities. All of the wind turbine equipment was delivered by April 2017, which allows the projects to qualify for 100% PTCs for 10 years following their expected commercial operation dates between 2018 and 2020. The ultimate outcome of these matters cannot be determined at this time.

(J) JOINT OWNERSHIP AGREEMENTS

Southern Company Gas

See Note 4 to the financial statements of Southern Company Gas in Item 8 of the Form 10-K for additional information.

Equity Method Investments

The carrying amounts of Southern Company Gas' equity method investments as of June 30, 2017 and December 31, 2016 and related income from those investments for the successor three and six month periods ended June 30, 2017 and the predecessor three and six month periods ended June 30, 2016 were as follows:

Balance Sheet Information	**June 30, 2017**	December 31, 2016
	(in millions)	
SNG	**$ 1,405**	$ 1,394
Atlantic Coast Pipeline	**53**	33
PennEast Pipeline	**45**	22
Triton	**43**	44
Pivotal JAX LNG, LLC	**32**	16
Horizon Pipeline	**31**	30
Other	**1**	2
Total	**$ 1,610**	$ 1,541

Income Statement Information	**Successor** Three Months Ended June 30, 2017	Predecessor Three Months Ended June 30, 2016	**Successor** Six Months Ended June 30, 2017	Predecessor Six Months Ended June 30, 2016
	(in millions)	*(in millions)*	*(in millions)*	*(in millions)*
SNG	**$ 24**	$ —	**$ 58**	$ —
Triton	**2**	1	**2**	1
PennEast Pipeline	**1**	—	**4**	—
Atlantic Coast Pipeline	**2**	—	**3**	—
Horizon Pipeline	**—**	—	**1**	1
Total	**$ 29**	$ 1	**$ 68**	$ 2

Southern Natural Gas

In September 2016, Southern Company Gas, through a wholly-owned, indirect subsidiary, acquired a 50% equity interest in SNG, which is accounted for as an equity method investment. On March 31, 2017, Southern Company

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

Gas made an additional $50 million contribution to maintain its 50% equity interest in SNG. See Note 11 to the financial statements of Southern Company Gas under "Investment in SNG" in Item 8 of the Form 10-K for additional information on this investment. Selected financial information of SNG for the three and six months ended June 30, 2017 is as follows:

Income Statement Information	Three Months Ended June 30, 2017	Six Months Ended June 30, 2017
	(in millions)	
Revenues	$ 143	$ 298
Operating income	$ 63	$ 147
Net income	$ 48	$ 114

(K) SEGMENT AND RELATED INFORMATION

Southern Company

The primary businesses of the Southern Company system are electricity sales by the traditional electric operating companies and Southern Power and the distribution of natural gas by Southern Company Gas. The four traditional electric operating companies – Alabama Power, Georgia Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages 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 the seven natural gas distribution utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations.

Southern Company's reportable business segments are the sale of electricity by the four traditional electric operating companies, the sale of electricity in the competitive wholesale market by Southern Power, and the sale of natural gas and other complementary products and services by Southern Company Gas. Revenues from sales by Southern Power to the traditional electric operating companies were $90 million and $190 million for the three and six months ended June 30, 2017 , respectively, and $107 million and $204 million for the three and six months ended June 30, 2016 , respectively. The "All Other" column includes the Southern Company parent entity, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include providing energy technologies and services to electric utilities and large industrial, commercial, institutional, and municipal customers; as well as investments in telecommunications and leveraged lease projects. All other inter-segment revenues are not material.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued) (UNAUDITED)

Financial data for business segments and products and services for the three and six months ended June 30, 2017 and 2016 was as follows:

	Electric Utilities							
	Traditional Electric Operating Companies	Southern Power	Eliminations	Total	Southern Company Gas	All Other	Eliminations	Consolidated
	(in millions)							
Three Months Ended June 30, 2017:								
Operating revenues	$ 4,157	$ 529	$ (101)	$ 4,585	$ 716	$ 166	$ (37)	$ 5,430
Segment net income (loss) [(a)(b)]	(1,442)	82	—	(1,360)	49	(68)	(2)	(1,381)
Six Months Ended June 30, 2017:								
Operating revenues	$ 7,943	$ 979	$ (206)	$ 8,716	$ 2,276	$ 289	$ (79)	$ 11,202
Segment net income (loss) [(a)(b)(c)]	(1,010)	151	—	(859)	288	(152)	—	(723)
Total assets at June 30, 2017	$ 71,503	$ 14,703	$ (317)	$ 85,889	$ 21,809	$ 2,348	$ (1,362)	$ 108,684
Three Months Ended June 30, 2016:								
Operating revenues	$ 4,115	$ 373	$ (109)	$ 4,379	$ —	$ 125	$ (45)	$ 4,459
Segment net income (loss) [(a)(b)]	599	89	—	688	—	(61)	(4)	623
Six Months Ended June 30, 2016:								
Operating revenues	$ 7,884	$ 688	$ (212)	$ 8,360	$ —	$ 172	$ (81)	$ 8,451
Segment net income (loss) [(a)(b)]	1,064	139	—	1,203	—	(84)	(7)	1,112
Total assets at December 31, 2016	$ 72,141	$ 15,169	$ (316)	$ 86,994	$ 21,853	$ 2,474	$ (1,624)	$ 109,697

(a) Attributable to Southern Company.

(b) Segment net income (loss) for the traditional electric operating companies includes pre-tax charges for estimated probable losses on the Kemper IGCC of $3.0 billion ($2.1 billion after tax) and $81 million ($50 million after tax) for the three months ended June 30, 2017 and 2016 , respectively, and $3.1 billion ($2.2 billion after tax) and $134 million ($83 million after tax) for the six months ended June 30, 2017 and 2016 , respectively. See Note (B) under " Integrated Coal Gasification Combined Cycle – Kemper IGCC Schedule and Cost Estimate " for additional information.

(c) Segment net income (loss) for the traditional electric operating companies also includes a pre-tax charge for the write-down of Gulf Power's ownership of Plant Scherer Unit 3 of $33 million ($20 million after tax) for the six months ended June 30, 2017 . See Note (B) under " Regulatory Matters – Gulf Power – Retail Base Rate Cases " for additional information.

Products and Services

	Electric Utilities' Revenues			
Period	Retail	Wholesale	Other	Total
	(in millions)			
Three Months Ended June 30, 2017	$ 3,777	$ 618	$ 190	$ 4,585
Three Months Ended June 30, 2016	3,748	446	185	4,379
Six Months Ended June 30, 2017	$ 7,171	$ 1,149	$ 396	$ 8,716
Six Months Ended June 30, 2016	7,124	842	394	8,360

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

Period	Southern Company Gas' Revenues			
	Gas Distribution Operations	Gas Marketing Services	Other	Total
	(in millions)			
Three Months Ended June 30, 2017	$ 557	$ 166	$ (7)	$ 716
Six Months Ended June 30, 2017	$ 1,689	$ 454	$ 133	$ 2,276

Southern Company Gas

Southern Company Gas manages its business through four reportable segments – gas distribution operations, gas marketing services, wholesale gas services, and gas midstream operations. The non-reportable segments are combined and presented as all other.

Gas distribution operations is the largest component of Southern Company Gas' business and includes natural gas local distribution utilities that construct, manage, and maintain intrastate natural gas pipelines and gas distribution facilities in seven states. Gas marketing services includes natural gas marketing to end-use customers primarily in Georgia and Illinois. Additionally, gas marketing services provides home equipment protection products and services. Wholesale gas services provides natural gas asset management and/or related logistics services for each of Southern Company Gas' utilities except Nicor Gas as well as for non-affiliated companies. Additionally, wholesale gas services engages in natural gas storage and gas pipeline arbitrage and related activities. Gas midstream operations primarily consists of Southern Company Gas' pipeline investments, with storage and fuel operations also aggregated into this segment. The all other column includes segments below the quantitative threshold for separate disclosure, including the subsidiaries that fall below the quantitative threshold for separate disclosure.

After the Merger, Southern Company Gas changed its segment performance measure to net income. In order to properly assess net income by segment, Southern Company Gas executed various intercompany note agreements to revise interest charges to its segments. Since such agreements did not exist in the predecessor period, Southern Company Gas is unable to provide the comparable net income.

Business segment financial data for the successor three and six months ended June 30, 2017 and the predecessor three and six months ended June 30, 2016 was as follows:

	Gas Distribution Operations	Gas Marketing Services	Wholesale Gas Services (*)	Gas Midstream Operations	Total	All Other	Eliminations	Consolidated
	(in millions)							
Successor – Three Months Ended June 30, 2017:								
Operating revenues	$ 603	$ 166	$ (12)	$ 12	$ 769	$ 3	$ (56)	$ 716
Segment net income	54	4	(17)	9	50	(1)	—	49
Successor – Six Months Ended June 30, 2017:								
Operating revenues	$ 1,783	$ 454	$ 119	$ 37	$ 2,393	$ 5	$ (122)	$ 2,276
Segment net income	171	35	51	25	282	6	—	288
Successor – Total assets at June 30, 2017	$ 18,257	$ 2,093	$ 989	$ 2,381	$ 23,720	$ 11,182	$ (13,093)	$ 21,809

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)
(UNAUDITED)

	Gas Distribution Operations	Gas Marketing Services	Wholesale Gas Services (*)	Gas Midstream Operations	Total	All Other	Eliminations	Consolidated
				(in millions)				
Predecessor – Three Months Ended June 30, 2016:								
Operating revenues	$ 547	$ 149	$ (95)	$ 10	$ 611	$ 2	$ (42)	$ 571
Segment EBIT	118	29	(112)	(5)	30	(55)	1	(24)
Predecessor – Six Months Ended June 30, 2016:								
Operating revenues	$ 1,575	$ 435	$ (32)	$ 25	$ 2,003	$ 4	$ (102)	$ 1,905
Segment EBIT	353	109	(68)	(6)	388	(60)	—	328
Successor – Total assets at December 31, 2016	$ 19,453	$ 2,084	$ 1,127	$ 2,211	$ 24,875	$ 11,145	$ (14,167)	$ 21,853

(*) The revenues for wholesale gas services are netted with costs associated with its energy and risk management activities. A reconciliation of operating revenues and intercompany revenues is shown in the following table.

	Third Party Gross Revenues	**Intercompany Revenues**	**Total Gross Revenues**	**Less Gross Gas Costs**	**Operating Revenues**
			(in millions)		
Successor – Three Months Ended June 30, 2017	$ 1,531	$ 123	$ 1,654	$ 1,666	$ (12)
Successor – Six Months Ended June 30, 2017	3,370	259	3,629	3,510	119
Predecessor – Three Months Ended June 30 , 2016	$ 1,061	$ 58	$ 1,119	$ 1,214	$ (95)
Predecessor – Six Months Ended June 30 , 2016	2,500	143	2,643	2,675	(32)

PART II — OTHER INFORMATION

Item 1. Legal Proceedings.

See the Notes to the Condensed Financial Statements herein for information regarding certain legal and administrative proceedings in which the registrants are involved.

I tem 1A. Risk Factors.

See RISK FACTORS in Item 1A of the Form 10-K for a discussion of the risk factors of the registrants. Except as described below, there have been no material changes to these risk factors from those previously disclosed in the Form 10-K.

The bankruptcy filing of the EPC Contractor is expected to have a material impact on the construction cost and schedule of, as well as the cost recovery for, Plant Vogtle Units 3 and 4 and could have a material impact on the financial statements of Southern Company and Georgia Power, and any inability or other failure by Toshiba to perform its obligations under the Guarantee Settlement Agreement could have a further material impact on the net cost to the Vogtle Owners to complete construction of Plant Vogtle Units 3 and 4, and therefore on the financial statements of Southern Company and Georgia Power.

See "Construction Risk" in Item 1A – Risk Factors of Southern Company and Georgia Power in the Form 10-K for a discussion of risks relating to major construction projects, including Plant Vogtle Units 3 and 4 and see Note (B) to the Condensed Financial Statements under "Regulatory Matters – Georgia Power – Nuclear Construction" herein and Note (E) to the Condensed Financial Statements under "DOE Loan Guarantee Borrowings" herein for additional information.

On March 29, 2017, the EPC Contractor filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. To provide for a continuation of work at Plant Vogtle Units 3 and 4, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into an interim assessment agreement with the EPC Contractor (Interim Assessment Agreement), which the bankruptcy court approved on March 30, 2017.

The Interim Assessment Agreement provided, among other items, that during the term of the Interim Assessment Agreement (i) Georgia Power was obligated to pay, on behalf of the Vogtle Owners, all costs accrued by the EPC Contractor for subcontractors and vendors for services performed or goods provided, with these amounts paid to the EPC Contractor, except that amounts accrued for Fluor Corporation (Fluor) were paid directly to Fluor; (ii) the EPC Contractor provided certain engineering, procurement, and management services for Plant Vogtle Units 3 and 4, to the same extent as contemplated by the Vogtle 3 and 4 Agreement, and Georgia Power, on behalf of the Vogtle Owners, made payments of $5.4 million per week for these services; (iii) Georgia Power had the right to make payments, on behalf of the Vogtle Owners, directly to subcontractors and vendors who had accounts past due with the EPC Contractor; (iv) the EPC Contractor used commercially reasonable efforts to provide information reasonably requested by Georgia Power as was necessary to continue construction and investigation of the completion status of Plant Vogtle Units 3 and 4; (v) the EPC Contractor rejected or accepted the Vogtle 3 and 4 Agreement by the termination of the Interim Assessment Agreement; and (vi) Georgia Power did not exercise any remedies against Toshiba under the Toshiba Guarantee. Under the Interim Assessment Agreement, all parties expressly reserved all rights and remedies under the Vogtle 3 and 4 Agreement and all related security and collateral under applicable law.

The Interim Assessment Agreement, as amended, expired on July 27, 2017. Georgia Power's aggregate liability for the Vogtle Owners under the Interim Assessment Agreement totaled approximately $650 million, of which $552 million had been paid or accrued as of June 30, 2017. Georgia Power's proportionate share of this aggregate liability totaled approximately $297 million.

Subsequent to the EPC Contractor bankruptcy filing, a number of subcontractors to the EPC Contractor, including Fluor Enterprises, Inc., a subsidiary of Fluor, alleged non-payment by the EPC Contractor for amounts owed for work performed on Plant Vogtle Units 3 and 4. Georgia Power, acting for itself and as agent for the Vogtle Owners, has taken, and continues to take, actions to remove liens filed by these subcontractors through the posting of surety bonds. Georgia Power estimates the aggregate liability, through July 31, 2017, of the Vogtle Owners for the removal of subcontractor liens and payment of other EPC Contractor pre-petition accounts payable to total approximately

$400 million , of which $354 million had been paid or accrued as of June 30, 2017. Georgia Power's proportionate share of this aggregate liability totaled approximately $183 million .

The Vogtle 3 and 4 Agreement also provided for liquidated damages upon the EPC Contractor's failure to fulfill the schedule and certain performance guarantees, each subject to an aggregate cap of 10% of the contract price, or approximately $920 million (approximately $420 million based on Georgia Power's ownership interest). Under the Toshiba Guarantee, Toshiba guaranteed certain payment obligations of the EPC Contractor, including any liability of the EPC Contractor for abandonment of work. In January 2016, Westinghouse delivered to the Vogtle Owners $920 million of letters of credit from financial institutions (Westinghouse Letters of Credit) to secure a portion of the EPC Contractor's potential obligations under the Vogtle 3 and 4 Agreement. The Westinghouse Letters of Credit are subject to annual renewals through June 30, 2020 and require 60 days' written notice to Georgia Power in the event the Westinghouse Letters of Credit will not be renewed.

Under the terms of the Vogtle 3 and 4 Agreement, the EPC Contractor did not have the right to terminate the Vogtle 3 and 4 Agreement for convenience. In the event of an abandonment of work by the EPC Contractor, the maximum liability of the EPC Contractor under the Vogtle 3 and 4 Agreement was 40% of the contract price (approximately $1.7 billion based on Georgia Power's ownership interest). In addition, the Vogtle Owners could terminate the Vogtle 3 and 4 Agreement for certain breaches by the EPC Contractor, including abandonment of work by the EPC Contractor.

On June 9, 2017, Georgia Power and the other Vogtle Owners and Toshiba entered into a settlement agreement regarding the Toshiba Guarantee (Guarantee Settlement Agreement). Pursuant to the Guarantee Settlement Agreement, Toshiba acknowledged the amount of its obligation under the Toshiba Guarantee is $3.68 billion (Guarantee Obligations), of which Georgia Power's proportionate share is approximately $1.7 billion, and that the Guarantee Obligations exist regardless of whether Plant Vogtle Units 3 and 4 are completed. The Guarantee Settlement Agreement also provides for a schedule of payments for the Guarantee Obligations, beginning in October 2017 and continuing through January 2021. In the event Toshiba receives certain payments, including sale proceeds, from or related to Westinghouse (or its subsidiaries) or Toshiba Nuclear Energy Holdings (UK) Limited (or its subsidiaries), it will hold a portion of such payments in trust for the Vogtle Owners and promptly pay them as offsets against any remaining Guarantee Obligations. Under the Guarantee Settlement Agreement, the Vogtle Owners will forbear from exercising certain remedies, including drawing on the Westinghouse Letters of Credit, until June 30, 2020, unless certain events of nonpayment, insolvency, or other material breach of the Guarantee Settlement Agreement by Toshiba occur. If such an event occurs, the balance of the Guarantee Obligations will become immediately due and payable, and the Vogtle Owners may exercise any and all rights and remedies, including drawing on the Westinghouse Letters of Credit without restriction. In addition, the Guarantee Settlement Agreement does not restrict the Vogtle Owners from fully drawing on the Westinghouse Letters of Credit in the event they are not renewed or replaced prior to the expiration date.

On June 23, 2017, Toshiba released a revised outlook for fiscal year 2016, which reflected a negative shareholders' equity balance of approximately $5 billion as of March 31, 2017, and announced that its independent audit process was continuing. Toshiba has also announced the existence of material events and conditions that raise substantial doubt about Toshiba's ability to continue as a going concern. As a result, substantial risk regarding the Vogtle Owners' ability to fully collect the Guarantee Obligations continues to exist. An inability or other failure by Toshiba to perform its obligations under the Guarantee Settlement Agreement could have a further material impact on the net cost to the Vogtle Owners to complete construction of Plant Vogtle Units 3 and 4 and, therefore, on Southern Company's and Georgia Power's financial statements.

Additionally, on June 9, 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the EPC Contractor entered into a services agreement (Services Agreement), which was amended and restated on July 20, 2017, for the EPC Contractor to transition construction management of Plant Vogtle Units 3 and 4 to Southern Nuclear and to provide ongoing design, engineering, and procurement services to Southern Nuclear. On July 20, 2017, the bankruptcy court approved the EPC Contractor's motion seeking authorization to (i) enter into the Services Agreement, (ii) assume and assign to the Vogtle Owners certain project-related contracts, (iii) join the

Vogtle Owners as counterparties to certain assumed project-related contracts, and (iv) reject the Vogtle 3 and 4 Agreement. The Services Agreement, and the EPC Contractor's rejection of the Vogtle 3 and 4 Agreement, became effective upon approval by the DOE on July 27, 2017. The Services Agreement will continue until the start-up and testing of Plant Vogtle Units 3 and 4 is complete and electricity is generated and sold from both units. The Services Agreement is terminable by the Vogtle Owners upon 30 days' written notice.

Georgia Power and the other Vogtle Owners are continuing to conduct comprehensive schedule and cost-to-complete assessments, as well as cancellation cost assessments, to determine the impact of the EPC Contractor's bankruptcy filing on the construction cost and schedule for Plant Vogtle Units 3 and 4. Georgia Power's preliminary assessment results indicate that its proportionate share of the remaining estimated cost to complete Plant Vogtle Units 3 and 4 ranges as follows:

Preliminary in-service dates					
Unit 3		February 2021	–		March 2022
Unit 4		February 2022	–		March 2023
			(in billions)		
Preliminary estimated cost to complete	$	3.9	–	$	4.6
CWIP as of June 30, 2017		4.5			4.5
Guarantee Obligations		(1.7)			(1.7)
Estimated capital costs	**$**	**6.7**	**–**	**$**	**7.4**
Vogtle Cost Settlement Agreement Revised Forecast		(5.7)			(5.7)
Estimated net additional capital costs	**$**	**1.0**	**–**	**$**	**1.7**

Georgia Power's estimates for cost to complete and schedule are based on preliminary analysis and remain subject to further refinement of labor productivity and consumable and commodity quantities and costs.

Georgia Power's estimated financing costs during the construction period total approximately $3.1 billion to $3.5 billion , of which approximately $1.4 billion had been incurred through June 30, 2017.

Georgia Power's preliminary cancellation cost estimate results indicate that its proportionate share of the estimated cancellation costs is approximately $400 million . As a result, as of June 30, 2017, total estimated costs subject to evaluation by Georgia Power and the Georgia PSC in the event of a cancellation decision are as follows:

	Preliminary Cancellation Cost Estimate	
	(in billions)	
CWIP as of June 30, 2017	$	4.5
Financing costs collected, net of tax		1.4
Cancellation costs (*)		0.4
Total	**$**	**6.3**

(*) The estimate for cancellation costs includes, but is not limited to, costs to terminate contracts for construction and other services, as well as costs to secure the Plant Vogtle Units 3 and 4 construction site.

The Guarantee Obligations continue to exist in the event of cancellation. In addition, under Georgia law, prudently incurred costs related to certificated projects cancelled by the Georgia PSC are allowed recovery, including carrying costs, in future retail rates. Georgia Power will continue working with the Georgia PSC and the other Vogtle Owners to determine future actions related to Plant Vogtle Units 3 and 4, including, but not limited to, the status of construction and rate recovery, and currently expects to include its recommendation in its seventeenth Vogtle Construction Monitoring report to be filed with the Georgia PSC in late August 2017.

The ultimate outcome of these matters is dependent on the completion of the assessments described above, as well as the related regulatory treatment, and cannot be determined at this time.

Item 6. Exhibits.

The exhibits below with an asterisk (*) preceding the exhibit number are filed herewith. The remaining exhibits have previously been filed with the SEC and are incorporated herein by reference. The exhibits marked with a pound sign (#) are management contracts or compensatory plans or arrangements.

(4) Instruments Describing Rights of Security Holders, Including Indentures

Southern Company

*	(a)1	-	Fourth Supplemental Indenture to Junior Subordinated Note Indenture, dated as of June 21, 2017, providing for the issuance of the Series 2017A 5.325% Junior Subordinated Notes due June 21, 2057.
*	(a)2	-	Nineteenth Supplemental Indenture to Senior Note Indenture, dated as of June 21, 2017, providing for the issuance of the Series 2017A Floating Rate Senior Notes due September 30, 2020.

Georgia Power

(c)1	-	Amendment No. 3, dated July 27, 2017 to Loan Guarantee Agreement dated February 20, 2014, between Georgia Power and the DOE. (Designated in Form 8-K dated July 27, 2017, File No. 1-6468, as Exhibit 4.1.)

Gulf Power

(d)	-	Twenty-Second Supplemental Indenture to Senior Note Indenture, dated as of May 18, 2017, providing for the issuance of the Series 2017A 3.30% Senior Notes due May 30, 2027. (Designated in Form 8-K dated May 15, 2017, File No. 001-31737, as Exhibit 4.2.)

Southern Company Gas

(g)1	-	Form of Southern Company Gas Capital Corporation's Series 2017A 4.400% Senior Notes due May 30, 2047. (Designated in Form 8-K dated May 4, 2017, File No. 1-14174, as Exhibit 4.1.)
(g)2	-	Form of Southern Company Gas' Guarantee related to the Series 2017A 4.400% Senior Notes due May 30, 2047. (Designated in Form 8-K dated May 4, 2017, File No. 1-14174, as Exhibit 4.3.)

(10) Material Contracts

Georgia Power

(c)1	-	Amendment No. 2 to Interim Assessment Agreement dated as of March 29, 2017, by and among Georgia Power, for itself and as agent for Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Westinghouse, WECTEC Staffing Services LLC, and WECTEC. (Designated in Form 8-K dated May 12, 2017, File No. 1-6468, as Exhibit 10.1.)
(c)2	-	Amendment No. 3 to Interim Assessment Agreement dated as of March 29, 2017, by and among Georgia Power, for itself and as agent for Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Westinghouse, WECTEC Staffing Services LLC, and WECTEC. (Designated in Form 8-K dated June 3, 2017, File No. 1-6468, as Exhibit 10.1.)

(c)3 - Amendment No. 4 to Interim Assessment Agreement dated as of March 29, 2017, by and among Georgia Power, for itself and as agent for Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Westinghouse, WECTEC Staffing Services LLC, and WECTEC. (Designated in Form 8-K dated June 5, 2017, File No. 1-6468, as Exhibit 10.1.)

(c)4 - Amendment No. 5 to Interim Assessment Agreement dated as of March 29, 2017, by and among Georgia Power, for itself and as agent for Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Westinghouse, WECTEC Staffing Services LLC, and WECTEC. (Designated in Form 8-K dated June 16, 2017, File No. 1-6468, as Exhibit 10.2.)

(c)5 - Amendment No. 6 to Interim Assessment Agreement dated as of March 29, 2017, by and among Georgia Power, for itself and as agent for Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Westinghouse, WECTEC Staffing Services LLC, and WECTEC. (Designated in Form 8-K dated June 22, 2017, File No. 1-6468, as Exhibit 10.1.)

(c)6 - Amendment No. 7 to Interim Assessment Agreement dated as of March 29, 2017, by and among Georgia Power, for itself and as agent for Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Westinghouse, WECTEC Staffing Services LLC, and WECTEC. (Designated in Form 8-K dated June 28, 2017, File No. 1-6468, as Exhibit 10.1.)

(c)7 - Amendment No. 8 to Interim Assessment Agreement dated as of March 29, 2017, by and among Georgia Power, for itself and as agent for Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Westinghouse, WECTEC Staffing Services LLC, and WECTEC. (Designated in Form 8-K dated July 20, 2017, File No. 1-6468, as Exhibit 10.1.)

(c)8 - Settlement Agreement dated as of June 9, 2017, by and among Georgia Power, Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Toshiba Corporation. (Designated in Form 8-K dated June 16, 2017, File No. 1-6468, as Exhibit 10.1.)

* (c)9 - Amended and Restated Services Agreement dated as of June 20, 2017, by and among Georgia Power, for itself and as agent for Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and The City of Dalton, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Westinghouse and WECTEC. (Georgia Power has requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Georgia Power omitted such portions from the filing and filed them separately with the SEC.)

(24) Power of Attorney and Resolutions

Southern Company

(a) - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2016, File No. 1-3526 as Exhibit 24(a).)

Alabama Power

(b) - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2016, File No. 1-3164 as Exhibit 24(b).)

Georgia Power

(c) - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2016, File No. 1-6468 as Exhibit 24(c).)

Gulf Power

(d) - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2016, File No. 001-31737 as Exhibit 24(d).)

Mississippi Power

(e) - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2016, File No. 001-11229 as Exhibit 24(e).)

Southern Power

(f) - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2016, File No. 001-37803 as Exhibit 24(f).)

Southern Company Gas

(g) - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2016, File No. 1-14174 as Exhibit 24(g).)

(31) Section 302 Certifications

Southern Company

* (a)1 - Certificate of Southern Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (a)2 - Certificate of Southern Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Alabama Power

* (b)1 - Certificate of Alabama Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (b)2 - Certificate of Alabama Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Georgia Power

* (c)1 - Certificate of Georgia Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (c)2 - Certificate of Georgia Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Gulf Power

* (d)1 - Certificate of Gulf Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (d)2 - Certificate of Gulf Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

* (e)1 - Certificate of Mississippi Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

*	(e)2	-	Certificate of Mississippi Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Southern Power

*	(f)1	-	Certificate of Southern Power Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(f)2	-	Certificate of Southern Power Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Southern Company Gas

*	(g)1	-	Certificate of Southern Company Gas' Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(g)2	-	Certificate of Southern Company Gas' Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(32) Section 906 Certifications

Southern Company

*	(a)	-	Certificate of Southern Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Alabama Power

*	(b)	-	Certificate of Alabama Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Georgia Power

*	(c)	-	Certificate of Georgia Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Gulf Power

*	(d)	-	Certificate of Gulf Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

*	(e)	-	Certificate of Mississippi Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Southern Power

*	(f)	-	Certificate of Southern Power Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Southern Company Gas

*	(g)	-	Certificate of Southern Company Gas' Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

(101) Interactive Data Files

*	INS	-	XBRL Instance Document
*	SCH	-	XBRL Taxonomy Extension Schema Document
*	CAL	-	XBRL Taxonomy Calculation Linkbase Document
*	DEF	-	XBRL Definition Linkbase Document
*	LAB	-	XBRL Taxonomy Label Linkbase Document
*	PRE	-	XBRL Taxonomy Presentation Linkbase Document

THE SOUTHERN COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

THE SOUTHERN COMPANY

By *Thomas A. Fanning*
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

By *Art P. Beattie*
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: August 1, 2017

ALABAMA POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

ALABAMA POWER COMPANY

By *Mark A. Crosswhite*
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

By *Philip C. Raymond*
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: August 1, 2017

GEORGIA POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

GEORGIA POWER COMPANY

By *W. Paul Bowers*
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

By *W. Ron Hinson*
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: August 1, 2017

GULF POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

GULF POWER COMPANY

By *S. W. Connally, Jr.*
Chairman, President and Chief Executive Officer
(Principal Executive Officer)

By *Xia Liu*
Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: August 1, 2017

MISSISSIPPI POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

MISSISSIPPI POWER COMPANY

By *Anthony L. Wilson*
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

By *Moses H. Feagin*
Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: August 1, 2017

SOUTHERN POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

SOUTHERN POWER COMPANY

By *Joseph A. Miller*
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

By *William C. Grantham*
Senior Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: August 1, 2017

SOUTHERN COMPANY GAS

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

SOUTHERN COMPANY GAS

By *Andrew W. Evans*
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

By *Elizabeth W. Reese*
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: August 1, 2017

THE SOUTHERN COMPANY

TO

WELLS FARGO BANK, NATIONAL ASSOCIATION,
TRUSTEE

FOURTH SUPPLEMENTAL INDENTURE

DATED AS OF JUNE 21, 2017

$500,000,000

SERIES 2017A 5.325% JUNIOR SUBORDINATED NOTES

DUE JUNE 21, 2057

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[1] This Table of Contents does not constitute part of the Indenture or have any bearing upon the interpretation of any of its terms and provisions.

THIS FOURTH SUPPLEMENTAL INDENTURE is made as of the 21st day of June, 2017, by and between THE SOUTHERN COMPANY, a Delaware corporation, 30 Ivan Allen Jr. Blvd., N.W., Atlanta, Georgia 30308 (the "Company"), and WELLS FARGO BANK, NATIONAL ASSOCIATION, a national banking association, 150 East 42nd Street, 40th Floor, New York, New York 10017 (the "Trustee").

W I T N E S S E T H:

WHEREAS, the Company has heretofore entered into a Subordinated Note Indenture, dated as of October 1, 2015 (the "Original Indenture"), with Wells Fargo Bank, National Association;

WHEREAS, the Original Indenture is incorporated herein by this reference and the Original Indenture, as heretofore supplemented and as further supplemented by this Fourth Supplemental Indenture, is herein called the "Indenture";

WHEREAS, under the Original Indenture, a new series of Junior Subordinated Notes may at any time be established pursuant to a supplemental indenture executed by the Company and the Trustee;

WHEREAS, the Company proposes to create under the Indenture a new series of Junior Subordinated Notes;

WHEREAS, additional Junior Subordinated Notes of other series hereafter established, except as may be limited in the Original Indenture as at the time supplemented and modified, may be issued from time to time pursuant to the Indenture as at the time supplemented and modified; and

WHEREAS, all conditions necessary to authorize the execution and delivery of this Fourth Supplemental Indenture and to make it a valid and binding obligation of the Company have been done or performed.

NOW, THEREFORE, in consideration of the agreements and obligations set forth herein and for other good and valuable consideration, the sufficiency of which is hereby acknowledged, the parties hereto hereby agree as follows:

ARTICLE 1
Series 2017A Junior Subordinated Notes

SECTION 101. Establishment. There is hereby established a new series of Junior Subordinated Notes to be issued under the Indenture, to be designated as the Company's Series 2017A 5.325% Junior Subordinated Notes due June 21, 2057 (the "Series 2017A Notes").

There are to be authenticated and delivered $500,000,000 principal amount of Series 2017A Notes, and such principal amount of the Series 2017A Notes may be increased from time to time pursuant to Section 301 of the Original Indenture. All Series 2017A Notes need not be issued at the same time and such series may be reopened at any time, without the consent of any Holder, for

issuances of additional Series 2017A Notes. Any such additional Series 2017A Notes will have the same interest rate, maturity and other terms as those initially issued (except for the public offering price and issue date and the initial interest accrual date and initial Interest Payment Date (as defined below), if applicable). No Series 2017A Notes shall be authenticated and delivered in excess of the principal amount as so increased except as provided by Sections 203, 303, 304, 907 or 1107 of the Original Indenture. The Series 2017A Notes shall be issued in fully registered form.

The Series 2017A Notes shall be issued in the form of one or more Global Securities in substantially the form set out in Exhibit A hereto. The Depositary with respect to the Series 2017A Notes shall be The Depository Trust Company.

The form of the Trustee's Certificate of Authentication for the Series 2017A Notes shall be in substantially the form set forth in Exhibit B hereto.

Each Series 2017A Note shall be dated the date of authentication thereof and shall bear interest from the date of original issuance thereof or from the most recent Interest Payment Date to which interest has been paid or duly provided for.

SECTION 102. Definitions. The following defined terms used herein shall, unless the context otherwise requires, have the meanings specified below. Capitalized terms used herein for which no definition is provided herein shall have the meanings set forth in the Original Indenture.

"1933 Act" has the meaning set forth in Section 106 of this Fourth Supplemental Indenture.

"Additional Interest" has the meaning set forth in Section 104 of this Fourth Supplemental Indenture.

"Administrative Action" means any judicial decision or any official administrative pronouncement, ruling, regulatory procedure, notice or announcement including any notice or announcement of intent to issue or adopt any administrative pronouncement, ruling, regulatory procedure or regulation.

"Applicable Rating Agency" means any Rating Agency that (i)(a) published a rating for the Company on the date of initial issuance of the Series 2017A Notes and (b) publishes a rating for the Company at such time as a Rating Agency Event occurs, or (ii) any successor to a Rating Agency described in the preceding clause (i).

"Distribution Compliance Period" has the meaning set forth in Section 107 of this Fourth Supplemental Indenture.

"Interest Payment Dates" means June 21 and December 21 of each year, commencing December 21, 2017.

"Optional Deferral Period" has the meaning set forth in Section 104 of this Fourth Supplemental Indenture.

"Original Issue Date" means June 21, 2017.

“Rating Agency” means any nationally recognized statistical rating organization (within the meaning of Section 3(a)(62) of the Securities Exchange Act of 1934, as amended).

“Rating Agency Event” means a change to the methodology or criteria that were employed by an Applicable Rating Agency for purposes of assigning equity credit to securities such as the Series 2017A Notes on the date of initial issuance of the Series 2017A Notes (the “current methodology”), which change either (i) shortens the period of time during which equity credit pertaining to the Series 2017A Notes would have been in effect had the current methodology not been changed by the Applicable Rating Agency, or (ii) reduces the amount of equity credit assigned to the Series 2017A Notes by the Applicable Rating Agency as compared with the amount of equity credit that such Rating Agency assigned to the Series 2017A Notes as of the date of initial issuance of the Series 2017A Notes.

“Regular Record Date” means, with respect to each Interest Payment Date, the close of business (i) on the Business Day immediately preceding such Interest Payment Date if any Series 2017A Notes are issuable in the form of one or more Global Securities or (ii) on the 15th calendar day preceding such Interest Payment Date if no Series 2017A Notes are issuable in the form of one or more Global Securities (whether or not a Business Day).

“Regulation S Global Note” has the meaning set forth in Section 106 of this Fourth Supplemental Indenture.

“Regulation S Legend” has the meaning set forth in Section 106 of this Fourth Supplemental Indenture.

“Rule 144A Global Note” has the meaning set forth in Section 106 of this Fourth Supplemental Indenture.

“Rule 144A Legend” has the meaning set forth in Section 106 of this Fourth Supplemental Indenture.

“Securities Rate” has the meaning set forth in Section 103 of this Fourth Supplemental Indenture.

“Stated Maturity” means June 21, 2057.

“Tax Event” means that the Company shall have received an Opinion of Counsel experienced in such matters to the effect that, as a result of:

(a) any amendment to, clarification of, or change, including any announced prospective change, in the laws or treaties of the United States or any political subdivisions or taxing authorities, or any regulations under those laws or treaties;

(b) an Administrative Action;

(c) any amendment to, clarification of, or change in the official position or the interpretation of any Administrative Action or any interpretation or pronouncement that provides for a position

with respect to an Administrative Action that differs from the previously generally accepted position, in each case by any legislative body, court, governmental authority or regulatory body, regardless of the time or manner in which that amendment, clarification or change is introduced or made known; or

(d) a threatened challenge asserted in writing in connection with an audit of the Company or an audit of any of the subsidiaries of the Company, or a publicly-known threatened challenge asserted in writing against any other taxpayer that has raised capital through the issuance of securities that are substantially similar to the Series 2017A Notes, which amendment, clarification or change is effective or the Administrative Action is taken or issued, or interpretation or pronouncement is issued or threatened challenge is asserted or becomes publicly-known after the date of original issuance of the Series 2017A Notes, there is more than an insubstantial risk that interest payable by the Company on the Series 2017A Notes is not deductible, or within 90 days of the date of such opinion would not be deductible, in whole or in part, by the Company for United States federal income tax purposes.

SECTION 103. Payment of Principal and Interest . The principal of the Series 2017A Notes shall be due at the Stated Maturity (unless earlier redeemed). The unpaid principal amount of the Series 2017A Notes shall bear interest at the rate of 5.325% per annum (the "Securities Rate") until paid or duly provided for. Interest shall be paid semi-annually in arrears on each Interest Payment Date to the Person in whose name the Series 2017A Notes are registered at the close of business on the Regular Record Date for such Interest Payment Date, provided that interest payable at the Stated Maturity or on a Redemption Date as provided herein will be paid to the Person to whom principal is payable. So long as an Optional Deferral Period is not occurring, any such interest that is not so punctually paid or duly provided for will forthwith cease to be payable to the Holders on such Regular Record Date and may either be paid to the Person or Persons in whose name the Series 2017A Notes are registered at the close of business on a Special Record Date for the payment of such defaulted interest to be fixed by the Trustee, notice whereof shall be given to Holders of the Series 2017A Notes not less than ten (10) days prior to such Special Record Date, or be paid at any time in any other lawful manner not inconsistent with the requirements of any securities exchange, if any, on which the Series 2017A Notes shall be listed, and upon such notice as may be required by any such exchange, all as more fully provided in the Original Indenture.

Payments of interest on the Series 2017A Notes will include interest accrued to but excluding the respective Interest Payment Dates. Interest payments for the Series 2017A Notes shall be computed and paid on the basis of a 360-day year of twelve 30-day months. In the event that any date on which interest is payable on the Series 2017A Notes is not a Business Day, then payment of the interest payable on such date will be made on the next succeeding day that is a Business Day (and without any interest or other payment in respect of any such delay), with the same force and effect as if made on the date the payment was originally payable.

Payment of the principal and interest (including Additional Interest) due at the Stated Maturity or earlier redemption of the Series 2017A Notes shall be made upon surrender of the Series 2017A Notes at the Corporate Trust Office of the Trustee. The principal of and interest on the Series 2017A Notes (including Additional Interest) shall be paid in such coin or currency of the United

States of America as at the time of payment is legal tender for payment of public and private debts. Payments of interest (including interest on any Interest Payment Date)(including Additional Interest) will be made, subject to such surrender where applicable, at the option of the Company, (i) by check mailed to the address of the Person entitled thereto as such address shall appear in the Security Register or (ii) by wire transfer or other electronic transfer at such place and to such account at a banking institution in the United States as may be designated in writing to the Trustee at least sixteen (16) days prior to the date for payment by the Person entitled thereto.

SECTION 104. Deferral of Interest Payments . So long as no Event of Default has occurred and is continuing, the Company may, at its option, on one or more occasions, defer payment of all or part of the current and accrued interest otherwise due on the Series 2017A Notes by extending the interest payment period for up to ten (10) consecutive years (each period, commencing on the date that the first such interest payment would otherwise have been made, an “Optional Deferral Period”). A deferral of interest payments may not extend beyond the Stated Maturity or end on a day other than an Interest Payment Date. Any deferred interest on the Series 2017A Notes will accrue additional interest at the Securities Rate from the applicable Interest Payment Date to the date of payment, compounded semi-annually (such deferred interest and additional interest accrued thereon, “Additional Interest”), to the extent permitted under applicable law. No interest shall be due and payable during an Optional Deferral Period, except at the end of such Optional Deferral Period or upon a redemption of the Series 2017A Notes during such Optional Deferral Period.

So long as no Event of Default has occurred and is continuing, prior to the termination of any Optional Deferral Period, the Company may further defer the payment of interest by extending such Optional Deferral Period; provided that such Optional Deferral Period together with all such previous and further deferrals of interest payments shall not exceed ten (10) consecutive years at any one time or extend beyond the Stated Maturity. Upon the termination of any Optional Deferral Period, which shall be an Interest Payment Date, the Company shall pay all interest accrued and unpaid on the Series 2017A Notes, including any Additional Interest, to the Person in whose name the Series 2017A Notes are registered on the Regular Record Date for such Interest Payment Date, *provided* that interest accrued and unpaid on the Series 2017A Notes, including any Additional Interest, payable at Stated Maturity or on any Redemption Date will be paid to the Person to whom principal is payable. Once the Company pays all interest accrued and unpaid on the Series 2017A Notes, including any Additional Interest, it shall be entitled again to defer interest payments on the Series 2017A Notes as described above.

During an Optional Deferral Period, subject to the next succeeding sentence, the Company (a) shall not declare or pay any dividend or make any distributions with respect to, or redeem, purchase, acquire or make a liquidation payment with respect to, any of its capital stock, and (b) shall not make any payment of interest, principal or premium, if any, on or repay, repurchase or redeem any debt securities (including guarantees) issued by the Company which rank *pari passu* with or junior to the Series 2017A Notes. The preceding sentence, however, shall not restrict (i) any of the actions described in the preceding sentence resulting from any reclassification of the Company’s capital stock or the exchange or conversion of one class or series of the Company’s capital stock for another class or series of the Company’s capital stock, (ii) the purchase of fractional interests in shares of the Company’s capital stock pursuant to the conversion or exchange provisions

of such capital stock or the security being converted or exchanged, (iii) dividends, payments or distributions payable in shares of capital stock, (iv) redemptions, purchases or other acquisitions of shares of capital stock in connection with any employment contract, incentive plan, benefit plan or other similar arrangement of the Company or any of its subsidiaries or in connection with a dividend reinvestment or stock purchase plan, or (v) any declaration of a dividend in connection with implementation of any stockholders' rights plan, or the issuance of rights, stock or other property under any such plan, or the redemption, repurchase or other acquisition of any such rights pursuant thereto.

The Company shall provide to the Trustee notice, as provided in Section 105 of the Original Indenture, of its selection or extension of an Optional Deferral Period at least 10 Business Days and not more than 60 Business Days prior to the earlier of (a) the next applicable Interest Payment Date or (b) the date, if any, upon which the Company is required to give notice of such Interest Payment Date or the Regular Record Date thereof to any applicable self-regulatory organization. In addition, the Company shall deliver to the Trustee an Officers' Certificate stating that no default or Event of Default shall have occurred and be continuing. Subject to receipt of such Officers' Certificate, the Trustee shall forward such notice promptly to the Holders of the Series 2017A Notes as provided in Section 106 of the Original Indenture.

SECTION 105. Denominations . The Series 2017A Notes may be issued in the denominations of $200,000 and integral multiples of $1,000 in excess thereof.

SECTION 106. Global Securities . The Series 2017A Notes will be issued in the form of one or more Global Securities registered in the name of the Depositary (which shall be The Depository Trust Company) or its nominee. The Series 2017A Notes will be initially issued pursuant to an exemption or exemptions from the registration requirements of the Securities Act of 1933, as amended (the "1933 Act"). Beneficial interests in the Series 2017A Notes offered and sold to "qualified institutional buyers" (as defined in Rule 144A under the 1933 Act) in reliance upon Rule 144A under the 1933 Act shall be represented by one or more separate Global Securities (each, a "Rule 144A Global Note"). Each Rule 144A Global Note shall bear the Rule 144A legend in substantially the form set forth in Exhibit A hereto (the "Rule 144A Legend"). Beneficial interests in the Series 2017A Notes offered and sold to purchasers outside of the United States pursuant to Regulation S under the 1933 Act shall be represented by one or more separate Global Securities (each, a "Regulation S Global Note") and shall bear the Regulation S legend in substantially the form set forth in Exhibit A hereto (the "Regulation S Legend").

Owners of beneficial interests in such a Global Security will not be considered the Holders thereof for any purpose under the Indenture, and no Global Security representing a Series 2017A Note shall be exchangeable, except for another Global Security of like denomination and tenor to be registered in the name of the Depositary or its nominee or to a successor Depositary or its nominee. The rights of Holders of such Global Security shall be exercised only through the Depositary.

Subject to the procedures of the Depositary, a Global Security shall be exchangeable for Series 2017A Notes registered in the names of persons other than the Depositary or its nominee only if (i) the Depositary notifies the Company that it is unwilling or unable to continue as a Depositary for such Global Security and no successor Depositary shall have been appointed by the

Company, or if at any time the Depositary ceases to be a clearing agency registered under the Securities Exchange Act of 1934, as amended, at a time when the Depositary is required to be so registered to act as such Depositary and no successor Depositary shall have been appointed by the Company, in each case within 90 days after the Company receives such notice or becomes aware of such cessation, (ii) the Company in its sole discretion determines that such Global Security shall be so exchangeable, or (iii) there shall have occurred an Event of Default with respect to the Series 2017A Notes. Any Global Security that is exchangeable pursuant to the preceding sentence shall be exchangeable for Series 2017A Notes registered in such names as the Depositary shall direct.

Neither the Company, the Trustee nor any agent of the Company or the Trustee shall have any responsibility or liability for any aspect of the records relating to or payments made on account of beneficial ownership interests in a Global Security or for maintaining, supervising or reviewing any records relating to such beneficial ownership interests.

SECTION 107. Transfer . A Rule 144A Global Note may not be transferred on the Security Register except in compliance with the restrictions on transfer contained in the Rule 144A Legend and upon receipt by the Security Registrar of a completed and executed Transfer Certificate in the form contained in Exhibit A hereto. Prior to the expiration of 40 days beginning on and including the later of (i) the day on which the offering of the Series 2017A Notes commences and (ii) the Original Issue Date (the "Distribution Compliance Period"), a Regulation S Global Note may not be transferred on the Security Register except in compliance with the restrictions on transfer contained in the Regulation S Legend and upon receipt by the Security Registrar of a completed and executed Transfer Certificate in the form contained in Exhibit A. No service charge will be made for any transfer or exchange of Series 2017A Notes, but payment will be required of a sum sufficient to cover any tax or other governmental charge that may be imposed in connection therewith.

The transfer and exchange of beneficial interests in the Global Securities shall be effected through the Depositary, in accordance with this Fourth Supplemental Indenture (including applicable restrictions on transfer set forth herein, if any) and the procedures of the Depositary therefor.

Until the expiration of the Distribution Compliance Period, transfers by an owner of a beneficial interest in a Regulation S Global Note to a transferee who takes delivery of such interest through a Rule 144A Global Note will be made only upon receipt by the Trustee of a completed and executed Transfer Certificate in the form contained in Exhibit A hereto from the transferor of the beneficial interest to the effect that such transfer is being made to a person whom the transferor reasonably believes is a qualified institutional buyer (as defined in Rule 144A under the Securities Act) in a transaction meeting the requirements of Rule 144A and the requirements of applicable securities laws of any state of the United States or any other jurisdiction.

Transfers by an owner of a beneficial interest in the Rule 144A Global Note to a transferee who takes delivery through the Regulation S Global Note, whether before or after the expiration of the Distribution Compliance Period, will be made only upon receipt by the Trustee of a Transfer Certificate in the form contained in Exhibit A hereto from the transferor to the effect that such transfer is being made in accordance with Regulation S or Rule 144 under the Securities Act and that, if such transfer is being made prior to the expiration of the Distribution Compliance Period,

the interest transferred will be held immediately thereafter through Euroclear Bank S.A./N.V., as operator of the Euroclear System or Clearstream Banking, société anonyme, Luxembourg.

Any beneficial interest in one of the Global Securities that is transferred to a person who takes delivery in the form of an interest in another Global Security will, upon transfer, cease to be an interest in the initial Global Security and will become an interest in the other Global Security and, accordingly, will thereafter be subject to all transfer restrictions, if any, and other procedures applicable to beneficial interests in such other Global Security for as long as it remains such an interest.

Transfers of beneficial interests between a Rule 144A Global Note and a Regulation S Global Note, and other transfers relating to beneficial interests in the Global Securities, shall be reflected by endorsements of the Trustee, as custodian for The Depository Trust Company, on the schedules attached to such Rule 144A Global Note and Regulation S Global Note.

Neither the Trustee, the Security Registrar nor any transfer agent shall have any obligation or duty to monitor, determine or inquire as to compliance with any restrictions on transfer imposed under the Indenture or under applicable law with respect to any transfer of any interest in any Series 2017A Note (including any transfers between or among Depositary participants, members or beneficial owners in any Global Security) other than to require delivery of such certificates and other documentation or evidence as are expressly required by, and to do so if and when expressly required by, the terms of the Indenture, and to examine the same to determine substantial compliance as to form with the express requirements hereof.

Neither the Company nor the Trustee shall have any liability for acts or omissions of the Depositary, for the Depositary records of beneficial interest, for any transactions between the Depositary, any participant member of the Depositary and/or beneficial owner of any interest in any Series 2017A Notes, or in respect of any transfers effected by the Depositary or by any participant member of the Depositary or any beneficial owner of any interest in any Series 2017A Notes held through any such participant member of the Depositary.

The Company shall not be required (a) to issue, register the transfer of or exchange any Series 2017A Notes during a period beginning at the opening of business fifteen (15) days before the day of the mailing of a notice pursuant to Section 1104 of the Original Indenture identifying the serial numbers of the Series 2017A Notes to be called for redemption, and ending at the close of business on the day of the mailing, or (b) to register the transfer of or exchange any Series 2017A Notes theretofore selected for redemption in whole or in part, except the unredeemed portion of any Series 2017A Notes redeemed in part.

SECTION 108. Redemption at the Company's Option . At any time and from time to time on or after June 21, 2022, the Series 2017A Notes will be subject to redemption at the option of the Company in whole or in part upon not less than 30 nor more than 60 days' notice, at a Redemption Price equal to 100% of the principal amount of the Series 2017A Notes being redeemed plus accrued and unpaid interest (including any Additional Interest) on the Series 2017A Notes being redeemed to the Redemption Date.

In addition, before June 21, 2022, if a Tax Event shall occur and be continuing, the Company may redeem the Series 2017A Notes following the occurrence of that Tax Event, in whole, but not in part, at a Redemption Price equal to 100% of the principal amount to be redeemed plus any accrued but unpaid interest (including any Additional Interest) to the Redemption Date.

In addition, before June 21, 2022, if a Rating Agency Event shall occur and be continuing, the Company may redeem the Series 2017A Notes following the occurrence of that Rating Agency Event, in whole, but not in part, at a Redemption Price equal to 102% of the principal amount to be redeemed plus any accrued but unpaid interest (including any Additional Interest) to the Redemption Date.

In the event of redemption of the Series 2017A Notes in part only, a new Series 2017A Note or Notes for the unredeemed portion will be issued in the name or names of the Holders thereof upon the surrender thereof.

The Series 2017A Notes will not have a sinking fund.

Notice of redemption shall be given as provided in Section 1104 of the Original Indenture.

Any redemption of less than all of the Series 2017A Notes shall, with respect to the principal thereof, be divisible by $1,000.

SECTION 109. Events of Default.

The Event of Default set forth in Section 501(5) of the Original Indenture shall not apply to the Series 2017A Notes. The Events of Default set forth in paragraphs (1), (3), (6) and (7) shall apply to the Series 2017A Notes.

For purposes of this Section 109, the term “Default” means the following event: default in the performance or breach of any covenant or warranty of the Company in the Indenture (other than a covenant or warranty (i) a default in whose performance or whose breach is addressed in any paragraph of Section 501 of the Original Indenture (other than Section 501(5)) or (ii) which has expressly been included in the Indenture solely for the benefit of one or more series of Junior Subordinated Notes other than the Series 2017A Notes), and continuance of such default or breach for a period of 90 days after there has been given, by registered or certified mail, to the Company by the Trustee, or to the Company and the Trustee by the Holders of at least 25% in principal amount of the Outstanding Series 2017A Notes, a written notice specifying such default or breach and requiring it to be remedied and stating that such notice is a “Notice of Covenant Default” hereunder.

Upon the occurrence and continuance of a Default, the Trustee and the Holders of the Series 2017A Notes shall have the same rights and remedies, and shall be subject to the same limitations, restrictions, protections and exculpations, and the Company shall be subject to the same obligations and restrictions, in each case, as would apply if such Default was an Event of Default or an event which after notice or lapse of time or both would become an Event of Default; provided, that the principal of and accrued interest on the Series 2017A Notes may not be declared immediately due and payable by reason of the occurrence and continuation of a Default, and any notice of declaration

or acceleration based on such Default shall be null and void with respect to the Series 2017A Notes; provided, further that in case a Default has occurred and is continuing, the Trustee shall not be subject to Section 601(b) of the Original Indenture unless an Event of Default has occurred and is continuing.

SECTION 110. Information to Holders . Upon the request of any Holder, any holder of a beneficial interest in the Series 2017A Notes, or the Trustee (on behalf of a Holder or a holder of a beneficial interest in the Series 2017A Notes), the Company will furnish such information as is specified in paragraph (d)(4) of Rule 144A promulgated under the 1933 Act to Holders (and to holders of beneficial interests in the Series 2017A Notes), to prospective purchasers of the Series 2017A Notes (and of beneficial interests in the Series 2017A Notes) who are qualified institutional buyers or to the Trustee for delivery to such Holder or prospective purchasers of the Series 2017A Notes or beneficial interests therein, as the case may be, unless, at the time of such request, the Company is subject to the reporting requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended.

Delivery of information to the Trustee pursuant to this Section 110 is for informational purposes only and the Trustee’s receipt of such shall not constitute constructive notice of any information contained therein or determinable from information contained therein, including the Company’s compliance with any of its covenants under the Indenture.

ARTICLE 2
Miscellaneous Provisions

SECTION 201. Recitals by Company . The recitals in this Fourth Supplemental Indenture are made by the Company only and not by the Trustee, and all of the provisions contained in the Original Indenture in respect of the rights, privileges, immunities, powers and duties of the Trustee shall be applicable in respect of Series 2017A Notes and of this Fourth Supplemental Indenture as fully and with like effect as if set forth herein in full.

SECTION 202. Ratification and Incorporation of Original Indenture . As supplemented hereby, the Original Indenture is in all respects ratified and confirmed, and the Original Indenture, as supplemented by this Fourth Supplemental Indenture shall be read, taken and construed as one and the same instrument.

SECTION 203. Executed in Counterparts . This Fourth Supplemental Indenture may be simultaneously executed in several counterparts, each of which shall be deemed to be an original, and such counterparts shall together constitute but one and the same instrument.

SECTION 204. Legends . Except as determined by the Company in accordance with applicable law, each Series 2017A Note shall bear the applicable legends relating to restrictions on transfer pursuant to the securities laws in substantially the form set forth on Exhibit A hereto.

IN WITNESS WHEREOF, each party hereto has caused this instrument to be signed in its name and behalf by its duly authorized officer, all as of the day and year first above written.

THE SOUTHERN COMPANY

By: /s/Art P. Beattie

Art P. Beattie
Executive Vice President and Chief Financial Officer

WELLS FARGO BANK, NATIONAL ASSOCIATION, as Trustee

By: /s/Stefan Victory

Stefan Victory
Vice President

EXHIBIT A

FORM OF SERIES 2017A NOTE

[RULE 144A LEGEND FOR USE WITH RULE 144A GLOBAL NOTES]

NEITHER THIS NOTE NOR ANY BENEFICIAL INTEREST HEREIN HAS BEEN REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE “1933 ACT”). EACH HOLDER HEREOF, AND EACH OWNER OF A BENEFICIAL INTEREST HEREIN, BY PURCHASING THIS NOTE, AGREES FOR THE BENEFIT OF THE SOUTHERN COMPANY (THE “COMPANY”) THAT THIS NOTE MAY NOT BE RESOLD, PLEDGED OR OTHERWISE TRANSFERRED PRIOR TO THE DATE WHICH IS SIX MONTHS (IF ALL APPLICABLE CONDITIONS TO SUCH RESALE UNDER RULE 144 UNDER THE 1933 ACT (OR ANY SUCCESSOR PROVISION THEREOF) ARE SATISFIED) AFTER THE LATER OF THE ORIGINAL ISSUANCE DATE THEREOF, THE ISSUANCE DATE OF ANY SUBSEQUENT ISSUANCE OF ADDITIONAL NOTES OF THE SAME SERIES AND THE LAST DATE ON WHICH THE COMPANY OR ANY AFFILIATE THEREOF WAS THE OWNER OF THIS NOTE OR THE EXPIRATION OF SUCH SHORTER PERIOD AS MAY BE PRESCRIBED BY SUCH RULE 144 (OR SUCH SUCCESSOR PROVISION) PERMITTING RESALES OF THIS NOTE WITHOUT ANY CONDITIONS (THE “RESALE RESTRICTION TERMINATION DATE”) OTHER THAN (A)(1) TO THE COMPANY, (2) IN A TRANSACTION ENTITLED TO AN EXEMPTION FROM REGISTRATION PROVIDED BY RULE 144 UNDER THE 1933 ACT (IF AVAILABLE), (3) SO LONG AS THIS NOTE IS ELIGIBLE FOR RESALE PURSUANT TO RULE 144A UNDER THE 1933 ACT (“RULE 144A”), TO A PERSON WHOM THE SELLER REASONABLY BELIEVES IS A QUALIFIED INSTITUTIONAL BUYER WITHIN THE MEANING OF RULE 144A PURCHASING FOR ITS OWN ACCOUNT OR FOR THE ACCOUNT OF A QUALIFIED INSTITUTIONAL BUYER TO WHOM NOTICE IS GIVEN THAT THE RESALE, PLEDGE OR OTHER TRANSFER IS BEING MADE IN RELIANCE ON RULE 144A UNDER THE 1933 ACT (AS INDICATED BY THE BOX CHECKED BY THE TRANSFEROR ON THE CERTIFICATE OF TRANSFER ATTACHED TO THIS NOTE), (4) IN AN OFFSHORE TRANSACTION IN ACCORDANCE WITH RULE 903 OR 904 OF REGULATION S UNDER THE 1933 ACT (AS INDICATED BY THE BOX CHECKED BY THE TRANSFEROR ON THE CERTIFICATE OF TRANSFER ATTACHED TO THIS NOTE), (5) IN ACCORDANCE WITH ANOTHER APPLICABLE EXEMPTION FROM THE REGISTRATION REQUIREMENTS OF THE 1933 ACT (AND BASED UPON AN OPINION OF COUNSEL ACCEPTABLE TO THE COMPANY), OR (6) PURSUANT TO AN EFFECTIVE REGISTRATION STATEMENT UNDER THE 1933 ACT AND (B) IN EACH CASE IN ACCORDANCE WITH ANY APPLICABLE SECURITIES LAWS OF ANY STATE OF THE UNITED STATES. THE FOREGOING RESTRICTIONS ON RESALE WILL NOT APPLY SUBSEQUENT TO THE RESALE RESTRICTION TERMINATION DATE. THE HOLDER HEREOF, BY PURCHASING THIS NOTE, REPRESENTS AND AGREES FOR THE BENEFIT OF THE COMPANY THAT IT IS (i) A QUALIFIED INSTITUTIONAL BUYER WITHIN THE MEANING OF RULE 144A UNDER THE 1933 ACT OR (ii) A NON-U.S. PERSON OUTSIDE THE UNITED STATES WITHIN THE MEANING OF, OR AN ACCOUNT SATISFYING THE REQUIREMENTS OF, PARAGRAPH (k)(2) OF RULE 902 UNDER REGULATION S UNDER THE 1933 ACT. THE HOLDER OF THIS NOTE ACKNOWLEDGES THAT THE COMPANY OR THE TRUSTEE RESERVES THE RIGHT PRIOR TO ANY OFFER, SALE OR OTHER TRANSFER (1) PURSUANT TO CLAUSE (A)(2) PRIOR TO THE RESALE RESTRICTION TERMINATION DATE TO REQUIRE THE DELIVERY OF AN OPINION OF COUNSEL,

CERTIFICATIONS OR OTHER INFORMATION SATISFACTORY TO THE COMPANY AND THE TRUSTEE AND (2) IN EACH OF THE FOREGOING CASES, TO REQUIRE THAT A CERTIFICATE AS TO COMPLIANCE WITH CERTAIN CONDITIONS TO TRANSFER IS COMPLETED AND DELIVERED BY THE TRANSFEROR TO THE COMPANY AND THE TRUSTEE.

[REGULATION S LEGEND FOR USE WITH REGULATION S GLOBAL NOTES]

THE SECURITIES COVERED HEREBY HAVE NOT BEEN REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "1933 ACT"), AND MAY NOT BE OFFERED OR SOLD WITHIN THE UNITED STATES OR TO, OR FOR THE ACCOUNT OR BENEFIT OF, U.S. PERSONS (I) AS PART OF THEIR DISTRIBUTION AT ANY TIME OR (II) OTHERWISE UNTIL 40 DAYS AFTER THE LATER OF THE DATE OF THE COMMENCEMENT OF THE OFFERING OF THE SECURITIES AND THE DATE OF ORIGINAL ISSUANCE OF THE SECURITIES, EXCEPT IN EITHER CASE IN ACCORDANCE WITH REGULATION S OR RULE 144A UNDER THE 1933 ACT OR ANY OTHER AVAILABLE EXEMPTION FROM REGISTRATION UNDER THE 1933 ACT. TERMS USED ABOVE HAVE THE MEANINGS GIVEN TO THEM BY REGULATION S.

NO. __

CUSIP NO.

THE SOUTHERN COMPANY
SERIES 2017A 5.325% JUNIOR SUBORDINATED NOTE
DUE JUNE 21, 2057

Initial Principal Amount:	$__________
Regular Record Date:	One Business Day prior to Interest Payment Date (if any Series 2017A Notes are issuable in the form of one or more Global Securities) or 15th calendar day prior to Interest Payment Date (if no Series 2017A Notes are issuable in the form of one or more Global Securities)
Original Issue Date:	June 21, 2017
Stated Maturity:	June 21, 2057
Interest Payment Dates:	June 21 and December 21
Interest Rate:	5.325% per annum
Authorized Denomination:	$200,000 and integral multiples of $1,000 in excess thereof

The Southern Company, a Delaware corporation (the "Company," which term includes any successor corporation under the Indenture referred to on the reverse hereof), for value received, hereby promises to pay to ______________________________________, or registered assigns, the principal sum of _________ DOLLARS ($__________), or such other amount as indicated on the Schedule of Increases or Decreases in Global Security attached as Schedule I hereto, on the Stated Maturity shown above (or upon earlier redemption), and to pay interest thereon from the Original Issue Date shown above, or from the most recent Interest Payment Date to which interest has been paid or duly provided for, semi-annually in arrears on each Interest Payment Date as specified above, commencing on December 21, 2017 and on the Stated Maturity (or upon earlier redemption) at the rate per annum shown above until the principal hereof is paid or made available for payment and at such rate on any overdue principal and on any overdue installment of interest. The interest so payable, and punctually paid or duly provided for, on any Interest Payment Date (other than an Interest Payment Date that is the Stated Maturity or on a Redemption Date) will, as provided in such Indenture, be paid to the Person in whose name this Note (the "Note") is registered at the close of business on the Regular Record Date as specified above next preceding such Interest Payment Date, provided that any interest payable at the Stated Maturity or on any Redemption Date will be paid to the Person to whom principal is payable. Except as otherwise provided in the Indenture, any such interest not so punctually paid or duly provided for will forthwith cease to be payable to the Holder on such Regular Record Date and may either be paid to the Person in whose name this Note is registered at the close of business on a Special Record Date for the payment of such defaulted interest to be fixed by the Trustee, notice whereof shall be given to Holders of Notes of this series not less than 10 days prior to such Special Record Date, or be paid at any time in any other lawful manner not inconsistent with the requirements of any securities exchange, if any, on whic

h the Notes of this series shall be listed, and upon such notice as may be required by any such exchange, all as more fully provided in the Indenture.

Payments of interest on this Note will include interest accrued to but excluding the respective Interest Payment Dates. Interest payments for this Note shall be computed and paid on the basis of a 360-day year of twelve 30-day months. In the event that any date on which interest is payable on this Note is not a Business Day, then payment of the interest payable on such date will be made on the next succeeding day that is a Business Day (and without any interest or other payment in respect of any such delay), with the same force and effect as if made on the date the payment was originally payable. A "Business Day" shall mean any day other than a Saturday or a Sunday or a day on which banking institutions in New York City are authorized or required by law or executive order to remain closed or a day on which the Corporate Trust Office of the Trustee is closed for business.

So long as no Event of Default shall have occurred and be continuing, the Company may, at its option, on one or more occasions, defer payment of all or part of the current and accrued interest otherwise due on the Series 2017A Notes by extending the interest payment period for up to ten (10) consecutive years (each period, commencing on the date that the first such interest payment would otherwise have been made, an "Optional Deferral Period"). A deferral of interest payments may not extend beyond the Stated Maturity or end on a day other than an Interest Payment Date. As provided in the Indenture, Additional Interest on the Series 2017A Notes will accrue to the extent permitted by law. No interest shall be due and payable during an Optional Deferral Period, except at the end of such Optional Deferral Period or upon a redemption of the Series 2017A Notes during such Optional Deferral Period.

So long as no Event of Default shall have occurred and be continuing, prior to the termination of any Optional Deferral Period, the Company may further defer the payment of interest by extending such Optional Deferral Period; provided that such Optional Deferral Period together with all such previous and further deferrals of interest payments shall not exceed ten (10) consecutive years at any one time or extend beyond the Stated Maturity. Upon the termination of any Optional Deferral Period, which shall be an Interest Payment Date, the Company shall pay all interest accrued and unpaid on the Series 2017A Notes, including any Additional Interest, to the Person in whose name the Series 2017A Notes are registered on the Regular Record Date for such Interest Payment Date, *provided* that interest accrued and unpaid on the Series 2017A Notes, including any Additional Interest, payable at Stated Maturity or on any Redemption Date will be paid to the Person to whom principal is payable. Once the Company pays all interest accrued and unpaid on the Series 2017A Notes, including any Additional Interest, it shall be entitled again to defer interest payments on the Series 2017A Notes as described above.

During an Optional Deferral Period, subject to the next succeeding sentence, (a) the Company shall not declare or pay any dividend or make any distributions with respect to, or redeem, purchase, acquire or make a liquidation payment with respect to, any of its capital stock, and (b) the Company shall not make any payment of interest, principal or premium, if any, on or repay, repurchase or redeem any debt securities (including guarantees) issued by the Company which rank *pari passu* with or junior to the Series 2017A Notes. The preceding sentence, however, shall not restrict (i) any of the actions described in the preceding sentence resulting from any reclassification of the Company's capital stock or the exchange or conversion of one class or series of the Company's capital stock for another class or series of the Company's capital stock, (ii) the purchase of fractional interests in shares of the Company's capital stock pursuant to the conversion or exchange provisions of such capital stock or the security being converted or exchanged, (iii) dividends, payments or

distributions payable in shares of capital stock, (iv) redemptions, purchases or other acquisitions of shares of capital stock in connection with any employment contract, incentive plan, benefit plan or other similar arrangement of the Company or any of its subsidiaries or in connection with a dividend reinvestment or stock purchase plan, or (v) any declaration of a dividend in connection with implementation of any stockholders' rights plan, or the issuance of rights, stock or other property under any such plan, or the redemption, repurchase or other acquisition of any such rights pursuant thereto.

The Company shall provide to the Trustee written notice of its selection or extension of an Optional Deferral Period at least 10 Business Days and not more than 60 Business Days prior to the earlier of (a) the next applicable Interest Payment Date or (b) the date, if any, upon which the Company is required to give notice of such Interest Payment Date or the Regular Record Date thereof to any applicable self-regulatory organization. The Trustee shall forward such notice promptly to the Holders of the Series 2017A Notes.

Payment of the principal of and interest (including Additional Interest) due at the Stated Maturity or earlier redemption of the Series 2017A Notes shall be made upon surrender of the Series 2017A Notes at the Corporate Trust Office of the Trustee. The principal of and interest on the Series 2017A Notes (including Additional Interest) shall be paid in such coin or currency of the United States of America as at the time of payment is legal tender for payment of public and private debts. Payment of interest (including interest on an Interest Payment Date)(including Additional Interest) will be made, subject to such surrender where applicable, at the option of the Company, (i) by check mailed to the address of the Person entitled thereto as such address shall appear in the Security Register or (ii) by wire transfer or other electronic transfer at such place and to such account at a banking institution in the United States as may be designated in writing to the Trustee at least 16 days prior to the date for payment by the Person entitled thereto.

The indebtedness evidenced by this Note, including the principal hereof and interest hereon, is, to the extent provided in the Indenture, subordinate and junior in right of payment and upon liquidation to the prior payment in full of all Senior Indebtedness (as defined in the Indenture), and this Note is issued subject to the provisions of the Indenture with respect thereto. Each Holder of this Note, by accepting the same, (a) agrees to and shall be bound by such provisions, (b) authorizes and directs the Trustee on his behalf to take such action as may be necessary or appropriate to effectuate the subordination so provided, and (c) appoints the Trustee his attorney-in-fact for any and all such purposes. Each Holder hereof, by his acceptance hereof, waives all notice of the acceptance of the subordination provisions contained herein and in the Indenture by each holder of Senior Indebtedness, whether now outstanding or hereafter incurred, and waives reliance by each such holder upon said provisions.

REFERENCE IS HEREBY MADE TO THE FURTHER PROVISIONS OF THIS NOTE SET FORTH ON THE REVERSE HEREOF, WHICH FURTHER PROVISIONS SHALL FOR ALL PURPOSES HAVE THE SAME EFFECT AS IF SET FORTH AT THIS PLACE.

Unless the certificate of authentication hereon has been executed by the Trustee by manual signature, this Note shall not be entitled to any benefit under the Indenture or be valid or obligatory for any purpose.

IN WITNESS WHEREOF, the Company has caused this instrument to be duly executed under its corporate seal.

Dated:

THE SOUTHERN COMPANY

By: ________________________________
Title:

Attest:

____
Title:

{Seal of THE SOUTHERN COMPANY appears here}

CERTIFICATE OF AUTHENTICATION

This is one of the Junior Subordinated Notes referred to in the within-mentioned Indenture.

WELLS FARGO BANK, NATIONAL
ASSOCIATION, as Trustee

By: ______________________________
Authorized Signatory

(Reverse Side of Note)

This Note is one of a duly authorized issue of Junior Subordinated Notes of the Company (the "Notes"), issued and issuable in one or more series under a Subordinated Note Indenture, dated as of October 1, 2015, as supplemented (the "Indenture"), between the Company and Wells Fargo Bank, National Association, Trustee (the "Trustee," which term includes any successor trustee under the Indenture), to which Indenture and all indentures incidental thereto reference is hereby made for a statement of the respective rights, limitation of rights, duties and immunities thereunder of the Company, the Trustee and the Holders of the Notes issued thereunder and of the terms upon which said Notes are, and are to be, authenticated and delivered. This Note is one of the series designated on the face hereof as Series 2017A 5.325% Junior Subordinated Notes due June 21, 2057 (the "Series 2017A Notes") which is unlimited in principal amount. Capitalized terms used herein for which no definition is provided herein shall have the meanings set forth in the Indenture.

The Series 2017A Notes will not have a sinking fund.

At any time and from time to time on or after June 21, 2022, the Series 2017A Notes will be subject to redemption at the option of the Company in whole or in part upon not less than 30 nor more than 60 days' notice, at a Redemption Price equal to 100% of the principal amount of the Series 2017A Notes being redeemed plus accrued and unpaid interest (including any Additional Interest) on the Series 2017A Notes being redeemed to the Redemption Date.

In addition, if a Tax Event shall occur and be continuing, the Company may redeem the Series 2017A Notes following the occurrence of that Tax Event, in whole, but not in part, before June 21, 2022, at a Redemption Price equal to 100% of the principal amount to be redeemed plus any accrued but unpaid interest (including any Additional Interest) to the Redemption Date.

"Administrative Action" means any judicial decision or any official administrative pronouncement, ruling, regulatory procedure, notice or announcement including any notice or announcement of intent to issue or adopt any administrative pronouncement, ruling, regulatory procedure or regulation.

"Tax Event" means that the Company shall have received an Opinion of Counsel experienced in such matters to the effect that, as a result of:

(a) any amendment to, clarification of, or change, including any announced prospective change, in the laws or treaties of the United States or any political subdivisions or taxing authorities, or any regulations under those laws or treaties;

(b) an Administrative Action;

(c) any amendment to, clarification of, or change in the official position or the interpretation of any Administrative Action or any interpretation or pronouncement that provides for a position with respect to an Administrative Action that differs from the previously generally accepted position, in each case by any legislative body, court, governmental authority or regulatory body, regardless of the time or manner in which that amendment, clarification or change is introduced or made known; or

(d) a threatened challenge asserted in writing in connection with an audit of the Company or an audit of any of the subsidiaries of the Company, or a publicly-known threatened challenge

asserted in writing against any other taxpayer that has raised capital through the issuance of securities that are substantially similar to the Series 2017A Notes, which amendment, clarification or change is effective or the Administrative Action is taken or issued, or interpretation or pronouncement is issued or threatened challenge is asserted or becomes publicly-known after the date of original issuance of the Series 2017A Notes, there is more than an insubstantial risk that interest payable by the Company on the Series 2017A Notes is not deductible, or within 90 days of the date of such opinion would not be deductible, in whole or in part, by the Company for United States federal income tax purposes.

In addition, if a Rating Agency Event shall occur and be continuing, the Company may redeem the Series 2017A Notes following the occurrence of that Rating Agency Event, in whole, but not in part, before June 21, 2022, at a Redemption Price equal to 102% of the principal amount to be redeemed plus any accrued but unpaid interest (including any Additional Interest) to the Redemption Date.

"Applicable Rating Agency" means any Rating Agency that (i)(a) published a rating for the Company on the date of initial issuance of the Series 2017A Notes and (b) publishes a rating for the Company at such time as a Rating Agency Event occurs, or (ii) any successor to a Rating Agency described in the preceding clause (i).

"Rating Agency" means any nationally recognized statistical rating organization (within the meaning of Section 3(a)(62) of the Securities Exchange Act of 1934, as amended).

"Rating Agency Event" means a change to the methodology or criteria that were employed by an Applicable Rating Agency for purposes of assigning equity credit to securities such as the Series 2017A Notes on the date of initial issuance of the Series 2017A Notes (the "current methodology"), which change either (i) shortens the period of time during which equity credit pertaining to the Series 2017A Notes would have been in effect had the current methodology not been changed by the Applicable Rating Agency, or (ii) reduces the amount of equity credit assigned to the Series 2017A Notes by the Applicable Rating Agency as compared with the amount of equity credit that such Rating Agency has assigned to the Series 2017A Notes as of the date of initial issuance of the Series 2017A Notes.

In the event of redemption of this Note in part only, a new Note or Notes of this series for the unredeemed portion hereof will be issued in the name of the Holder hereof upon the surrender hereof. The Series 2017A Notes will not have a sinking fund.

If an Event of Default with respect to the Notes of this series shall occur and be continuing, the principal of the Notes of this series may be declared due and payable in the manner, with the effect and subject to the conditions provided in the Indenture.

The Indenture permits, with certain exceptions as therein provided, the amendment thereof and the modification of the rights and obligations of the Company and the rights of the Holders of the Notes of each series to be affected under the Indenture at any time by the Company and the Trustee with the consent of the Holders of not less than a majority in principal amount of the Notes at the time Outstanding of each series to be affected. The Indenture also contains provisions permitting the Holders of specified percentages in principal amount of the Notes of each series at the time Outstanding, on behalf of the Holders of all Notes of such series, to waive compliance by the Company with certain provisions of the Indenture and certain past defaults under the Indenture and their consequences. Any such consent or waiver by the Holder of this Note shall be conclusive and binding upon such Holder and upon all future Holders of this Note and of any Note issued upon

the registration of transfer hereof or in exchange hereof or in lieu hereof, whether or not notation of such consent or waiver is made upon this Note.

No reference herein to the Indenture and no provision of this Note or of the Indenture shall alter or impair the obligation of the Company, which is absolute and unconditional, to pay the principal of and interest on this Note at the times, place and rate, and in the coin or currency, herein prescribed.

As provided in the Indenture and subject to certain limitations therein set forth, the transfer of this Note is registrable in the Security Register, upon surrender of this Note for registration of transfer at the office or agency of the Company for such purpose, duly endorsed by, or accompanied by a written instrument of transfer in form satisfactory to the Company and the Security Registrar and duly executed by, the Holder hereof or his attorney duly authorized in writing, together with the completed and executed Transfer Certificate attached hereto (as applicable), and thereupon one or more new Notes of this series, of authorized denominations and of like tenor and for the same aggregate principal amount, will be issued to the designated transferee or transferees. No service charge shall be made for any such registration of transfer or exchange, but the Company may require payment of a sum sufficient to cover any tax or other governmental charge payable in connection therewith.

Prior to due presentment of this Note for registration of transfer, the Company, the Trustee and any agent of the Company or the Trustee may treat the Person in whose name this Note is registered as the owner hereof for all purposes, whether or not this Note be overdue, and neither the Company, the Trustee nor any such agent shall be affected by notice to the contrary.

The Notes of this series are issuable only in registered form without coupons in denominations of $200,000 and integral multiples of $1,000 in excess thereof. As provided in the Indenture and subject to certain limitations therein set forth, Notes of this series are exchangeable for a like aggregate principal amount of Notes of this series of a different authorized denomination, as requested by the Holder surrendering the same upon surrender of the Note or Notes to be exchanged at the office or agency of the Company.

The Company and, by acceptance of this Series 2017A Note or a beneficial interest in this Series 2017A Note, each Holder hereof and any person acquiring a beneficial interest herein, agree that for United States federal, state and local tax purposes it is intended that this Series 2017A Note constitute indebtedness.

This Note shall be governed by, and construed in accordance with, the internal laws of the State of New York.

ABBREVIATIONS

The following abbreviations, when used in the inscription on the face of this instrument, shall be construed as though they were written out in full according to applicable laws or regulations:

TEN COM- as tenants in common

TEN ENT- as tenants by the entireties

JT TEN- as joint tenants with right of survivorship and not as tenants in common

UNIF GIFT MIN ACT- _______ Custodian ________
(Cust) (Minor)

under Uniform Gifts to Minors Act

____
(State)

Additional abbreviations may also be used though not on the above list.

FOR VALUE RECEIVED, the undersigned hereby sell(s) and transfer(s) unto

(please insert Social Security or other identifying number of assignee)

PLEASE PRINT OR TYPEWRITE NAME AND ADDRESS, INCLUDING POSTAL ZIP CODE OF ASSIGNEE

the within Note and all rights thereunder, hereby irrevocably constituting and appointing

agent to transfer said Note on the books of the Company, with full power of substitution in the premises.

Dated: ___________________________ ____

____

NOTICE: The signature to this assignment must correspond with the name as written upon the face of the within instrument in every particular without alteration or enlargement, or any change whatever.

TRANSFER CERTIFICATE

In connection with any transfer of any of the Series 2017A Notes evidenced by this certificate [prior to the expiration of the Distribution Compliance Period] [1] , the undersigned confirms that such Series 2017A Notes are being:

CHECK ONE BOX BELOW

(1) ☐ exchanged for the undersigned's own account without transfer; or

(2) ☐ transferred to the Company; or

(3) ☐ transferred to a person whom the undersigned reasonably believes is a "qualified institutional buyer" within the meaning of Rule 144A under the Securities Act of 1933, as amended (the "1933 Act"), purchasing for its own account or for the account of a "qualified institutional buyer" to whom notice is given that the resale, pledge or other transfer is being made in reliance on Rule 144A under the 1933 Act; or

(4) ☐ transferred pursuant to an exemption under Rule 144 under the 1933 Act; or

(5) ☐ transferred in an offshore transaction in accordance with Rule 903 or Rule 904 of Regulation S under the 1933 Act; or

(6) ☐ transferred pursuant to another available exemption from the registration requirements of the 1933 Act; or

(7) ☐ transferred pursuant to an effective registration statement under the 1933 Act.

Unless one of the boxes is checked, the Trustee will refuse to register any of the Series 2017A Notes evidenced by this certificate in the name of any person other than the registered Holder thereof; provided , however , that if box (4) or (6) is checked, the Company may require, prior to registering any such transfer of the Series 2017A Notes, such legal opinions, certifications and other information as the Company has reasonably requested to confirm that such transfer is being made pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the 1933 Act, such as the exemption provided by Rule 144 under the 1933 Act; provided , further , that if box (3) is checked, the transferee must certify that it is a qualified institutional buyer as defined in Rule 144A.

Date: ____________________

____
Signature

____
Tax Identification Number

[1] [To be included for Regulation S Global Notes only.]

TO BE COMPLETED BY PURCHASER IF (3) ABOVE IS CHECKED.

The undersigned represents and warrants that it is purchasing this Series 2017A Note for its own account or an account with respect to which it exercises sole investment discretion and that it and any such account is a "qualified institutional buyer" within the meaning of Rule 144A under the 1933 Act, and is aware that the sale to it is being made in reliance on Rule 144A and acknowledges that it has received such information regarding the Company as the undersigned has requested pursuant to Rule 144A or has determined not to request such information and that it is aware that the transferor is relying upon the undersigned's foregoing representations in order to claim the exemption from registration provided by Rule 144A.

Date: ______________________

____

Signature

NOTICE: If an entity, to be executed by an executive officer.

SCHEDULE I TO GLOBAL SECURITY

The initial amount of the Global Securities evidenced by this certificate is $_______________.

SCHEDULE OF INCREASES OR DECREASES IN GLOBAL SECURITY

The following increases or decreases in this Global Security have been made

Date	Amount of increase in Principal Amount of this Global Security	Amount of decrease in Principal Amount of this Global Security	Principal Amount of this Global Security following each decrease or increase	Signature of authorized signatory of Trustee or Securities Registrar

EXHIBIT B

CERTIFICATE OF AUTHENTICATION

This is one of the Junior Subordinated Notes referred to in the within-mentioned Indenture.

WELLS FARGO BANK, NATIONAL ASSOCIATION, as Trustee

By: ______________________________
Authorized Signatory

THE SOUTHERN COMPANY

TO

WELLS FARGO BANK, NATIONAL ASSOCIATION,
TRUSTEE

NINETEENTH SUPPLEMENTAL INDENTURE

DATED AS OF JUNE 21, 2017

SERIES 2017A FLOATING RATE SENIOR NOTES

DUE SEPTEMBER 30, 2020

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[1] This Table of Contents does not constitute part of the Indenture or have any bearing upon the interpretation of any of its terms and provisions.

THIS NINETEENTH SUPPLEMENTAL INDENTURE is made as of the 21 st day of June, 2017, by and between THE SOUTHERN COMPANY, a Delaware corporation, 30 Ivan Allen Jr. Blvd., N.W., Atlanta, Georgia 30308 (the "Company"), and Wells Fargo Bank, National Association, a national banking association, 150 East 42 nd Street, 40 th Floor, New York, New York 10017 (the "Trustee").

W I T N E S S E T H:

WHEREAS, the Company has heretofore entered into a Senior Note Indenture, dated as of January 1, 2007 (the "Original Indenture"), with Wells Fargo Bank, National Association;

WHEREAS, the Original Indenture is incorporated herein by this reference and the Original Indenture, as heretofore supplemented and as further supplemented by this Nineteenth Supplemental Indenture, is herein called the "Indenture";

WHEREAS, under the Original Indenture, a new series of Senior Notes may at any time be established pursuant to a supplemental indenture executed by the Company and the Trustee;

WHEREAS, the Company proposes to create under the Indenture a new series of Senior Notes;

WHEREAS, additional Senior Notes of other series hereafter established, except as may be limited in the Original Indenture as at the time supplemented and modified, may be issued from time to time pursuant to the Indenture as at the time supplemented and modified; and

WHEREAS, all conditions necessary to authorize the execution and delivery of this Nineteenth Supplemental Indenture and to make it a valid and binding obligation of the Company have been done or performed.

NOW, THEREFORE, in consideration of the agreements and obligations set forth herein and for other good and valuable consideration, the sufficiency of which is hereby acknowledged, the parties hereto hereby agree as follows:

ARTICLE 1

SERIES 2017A SENIOR NOTES

SECTION 101. Establishment. There is hereby established a new series of Senior Notes to be issued under the Indenture, to be designated as the Company's Series 2017A Floating Rate Senior Notes due September 30, 2020 (the "Series 2017A Notes").

There are to be authenticated and delivered $300,000,000 principal amount of Series 2017A Notes, and such principal amount of the Series 2017A Notes may be increased from time to time pursuant to Section 301 of the Original Indenture. All Series 2017A Notes need not be issued at the same time and such series may be reopened at any time, without the consent of any Holder, for issuances of additional Series 2017A Notes. Any such additional Series 2017A Notes will have the

same interest rate, maturity and other terms as those initially issued (except for the public offering price and issue date and the initial interest accrual date and initial Interest Payment Date (as defined below), if applicable). No Series 2017A Notes shall be authenticated and delivered in excess of the principal amount as so increased except as provided by Sections 203, 303, 304, 907 or 1107 of the Original Indenture. The Series 2017A Notes shall be issued in fully registered form.

The Series 2017A Notes shall be issued in the form of one or more Global Securities in substantially the form set out in Exhibit A hereto. The Depositary with respect to the Series 2017A Notes shall be The Depository Trust Company.

The form of the Trustee's Certificate of Authentication for the Series 2017A Notes shall be in substantially the form set forth in Exhibit B hereto.

Each Series 2017A Note shall be dated the date of authentication thereof and shall bear interest from the date of original issuance thereof or from the most recent Interest Payment Date to which interest has been paid or duly provided for.

SECTION 102. Definitions . The following defined terms used herein shall, unless the context otherwise requires, have the meanings specified below. Capitalized terms used herein for which no definition is provided herein shall have the meanings set forth in the Original Indenture.

"1933 Act" has the meaning set forth in Section 106 of this Nineteenth Supplemental Indenture.

"Calculation Agent" means Wells Fargo Bank, National Association, or its successor appointed by the Company, acting as calculation agent.

"Distribution Compliance Period" has the meaning set forth in Section 107 of this Nineteenth Supplemental Indenture.

"Interest Determination Date" means the second London Business Day immediately preceding the first day of the relevant Interest Period.

"Interest Payment Dates" means the 30th day of March, June, September and December, commencing September 30, 2017; provided, however, in the event that any Interest Payment Date (other than the Interest Payment Date that is the Stated Maturity or a Redemption Date) would otherwise be a day that is not a Business Day, the Interest Payment Date will be the next succeeding Business Day.

"Interest Period" means the period commencing on an Interest Payment Date (or, with respect to the initial Interest Period only, commencing on the Original Issue Date) and ending on the day before the next succeeding Interest Payment Date.

"LIBOR" means, with respect to any Interest Period, the rate (expressed as a percentage per annum) for deposits in U.S. dollars for a three-month period commencing on the first day of that Interest Period and ending on the next Interest Payment Date that appears on Reuters

LIBOR01 Page as of 11:00 a.m. (London time) on the Interest Determination Date for that Interest Period. If such rate does not appear on the Reuters LIBOR01 Page as of 11:00 a.m. (London time) on the Interest Determination Date for that Interest Period, LIBOR will be determined on the basis of the rates at which deposits in U.S. dollars for the Interest Period and in a principal amount of not less than $1,000,000 are offered to prime banks in the London interbank market by four major banks in the London interbank market (which may include affiliates of one or more of the underwriters of the Series 2017A Notes) selected by the Calculation Agent (after consultation with the Company), at approximately 11:00 a.m., London time, on the Interest Determination Date for that Interest Period. The Calculation Agent will request the principal London office of each such bank to provide a quotation of its rate. If at least two such quotations are provided, LIBOR with respect to that Interest Period will be the arithmetic mean of such quotations. If fewer than two quotations are provided, LIBOR with respect to that Interest Period will be the arithmetic mean of the rates quoted by three major banks in New York City (which may include affiliates of one or more of the underwriters of the Series 2017A Notes) selected by the Calculation Agent (after consultation with the Company), at approximately 11:00 a.m., New York City time, on the Interest Determination Date for that Interest Period for loans in U.S. dollars to leading European banks for that Interest Period and in a principal amount of not less than $1,000,000. However, if fewer than three banks selected by the Calculation Agent to provide quotations are quoting as described above, LIBOR for that Interest Period will be the same as LIBOR as determined for the previous Interest Period.

"London Business Day" means a day that is a Business Day and a day on which dealings in deposits in U.S. dollars are transacted, or with respect to any future date are expected to be transacted, in the London interbank market.

"Original Issue Date" means June 21, 2017.

"Regular Record Date" means, with respect to each Interest Payment Date, the 15th calendar day preceding such Interest Payment Date (whether or not a Business Day).

"Regulation S Global Note" has the meaning set forth in Section 106 of this Nineteenth Supplemental Indenture.

"Regulation S Legend" has the meaning set forth in Section 106 of this Nineteenth Supplemental Indenture.

"Rule 144A Global Note" has the meaning set forth in Section 106 of this Nineteenth Supplemental Indenture.

"Rule 144A Legend" has the meaning set forth in Section 106 of this Nineteenth Supplemental Indenture.

"Reuters LIBOR01 Page" means the display designated as Reuters LIBOR01 on the Reuters service (or such other page as may replace the Reuters LIBOR01 Page on that service, or such other service as may be nominated as the information vendor, for the purpose of displaying rates or prices comparable to the London Interbank Offered rate for U.S. dollar deposits).

"Stated Maturity" means September 30, 2020; provided that if the Stated Maturity is not a Business Day, the principal and interest due on that date will be payable on the next succeeding Business Day, and no interest shall accrue for the intervening period.

SECTION 103. Payment of Principal and Interest. The principal of the Series 2017A Notes shall be due at Stated Maturity (unless earlier redeemed). The unpaid principal amount of the Series 2017A Notes shall bear interest at the rates set quarterly pursuant to Section 104 hereof until paid or duly provided for. Interest shall be paid quarterly in arrears on each Interest Payment Date to the Person in whose name the Series 2017A Notes are registered at the close of business on the Regular Record Date for such Interest Payment Date, *provided* that interest payable at the Stated Maturity or on a Redemption Date as provided herein will be paid to the Person to whom principal is payable. Any such interest that is not so punctually paid or duly provided for will forthwith cease to be payable to the Holders on such Regular Record Date and may either be paid to the Person or Persons in whose name the Series 2017A Notes are registered at the close of business on a Special Record Date for the payment of such defaulted interest to be fixed by the Trustee, notice whereof shall be given to Holders of the Series 2017A Notes not less than ten (10) days prior to such Special Record Date, or be paid at any time in any other lawful manner not inconsistent with the requirements of any securities exchange, if any, on which the Series 2017A Notes shall be listed, and upon such notice as may be required by any such exchange, all as more fully provided in the Original Indenture.

Payments of interest on the Series 2017A Notes will include interest accrued to but excluding the respective Interest Payment Dates. Interest payments for the Series 2017A Notes shall be computed and paid on the basis of the actual number of days elapsed over a 360-day year.

Payment of the principal and interest due at the Stated Maturity or earlier redemption of the Series 2017A Notes shall be made upon surrender of the Series 2017A Notes at the Corporate Trust Office of the Trustee. The principal of and interest on the Series 2017A Notes shall be paid in such coin or currency of the United States of America as at the time of payment is legal tender for payment of public and private debts. Payments of interest (including interest on any Interest Payment Date) will be made, subject to such surrender where applicable, at the option of the Company, (i) by check mailed to the address of the Person entitled thereto as such address shall appear in the Security Register or (ii) by wire transfer or other electronic transfer at such place and to such account at a banking institution in the United States as may be designated in writing to the Trustee at least sixteen (16) days prior to the date for payment by the Person entitled thereto.

SECTION 104. Determination of Interest. The Series 2017A Notes will bear interest for each Interest Period at a per annum rate determined by the Calculation Agent, subject to the maximum interest rate permitted by New York or other applicable state law, as such law may be modified by United States law of general application. The interest rate applicable during each Interest Period will be equal to LIBOR on the Interest Determination Date for such Interest Period plus

0.70%; provided, that in no event shall the applicable interest rate be less than 0% for any Interest Period. Promptly upon such determination, the Calculation Agent will notify the Company and the Trustee, if the Trustee is not then serving as the Calculation Agent, of the interest rate for the new Interest Period. The interest rate determined by the Calculation Agent,

absent manifest error, shall be binding and conclusive upon the beneficial owners and Holders of the Series 2017A Notes, the Company and the Trustee.

Upon the request of a Holder of the Series 2017A Notes, the Calculation Agent will provide to such Holder the interest rate in effect on the date of such request and, if determined, the interest rate for the next Interest Period.

SECTION 105. Denominations. The Series 2017A Notes may be issued in denominations of $2,000 and integral multiples of $1,000 in excess thereof.

SECTION 106. Global Securities. The Series 2017A Notes will be issued in the form of one or more Global Securities registered in the name of the Depositary (which shall be The Depository Trust Company) or its nominee. The Series 2017A Notes will be initially issued pursuant to an exemption or exemptions from the registration requirements of the Securities Act of 1933, as amended (the "1933 Act"). Beneficial interests in the Series 2017A Notes offered and sold to "qualified institutional buyers" (as defined in Rule 144A under the 1933 Act) in reliance upon Rule 144A under the 1933 Act shall be represented by one or more separate Global Securities (each, a "Rule 144A Global Note"). Each Rule 144A Global Note shall bear the Rule 144A legend in substantially the form set forth in Exhibit A hereto (the "Rule 144A Legend"). Beneficial interests in the Series 2017A Notes offered and sold to purchasers outside of the United States pursuant to Regulation S under the 1933 Act shall be represented by one or more separate Global Securities (each, a "Regulation S Global Note") and shall bear the Regulation S legend in substantially the form set forth in Exhibit A hereto (the "Regulation S Legend").

Except under the limited circumstances described below, Series 2017A Notes represented by one or more Global Securities will not be exchangeable for, and will not otherwise be issuable as, Series 2017A Notes in definitive form. The Global Securities described above may not be transferred except by the Depositary to a nominee of the Depositary or by a nominee of the Depositary to the Depositary or another nominee of the Depositary or to a successor Depositary or its nominee.

Owners of beneficial interests in such a Global Security will not be considered the Holders thereof for any purpose under the Indenture, and no Global Security representing a Series 2017A Note shall be exchangeable, except for another Global Security of like denomination and tenor to be registered in the name of the Depositary or its nominee or to a successor Depositary or its nominee. The rights of Holders of such Global Security shall be exercised only through the Depositary.

Subject to the procedures of the Depositary, a Global Security shall be exchangeable for Series 2017A Notes registered in the names of persons other than the Depositary or its nominee only if (i) the Depositary notifies the Company that it is unwilling or unable to continue as a Depositary for such Global Security and no successor Depositary shall have been appointed by the Company, or if at any time the Depositary ceases to be a clearing agency registered under the Securities Exchange Act of 1934, as amended, at a time when the Depositary is required to be so

registered to act as such Depositary and no successor Depositary shall have been appointed by the Company, in each case within 90 days after the Company receives such notice or becomes aware of such cessation, (ii) the Company in its sole discretion determines that such Global Security shall be so exchangeable, or (iii) there shall have occurred an Event of Default with respect to the Series

2017A Notes. Any Global Security that is exchangeable pursuant to the preceding sentence shall be exchangeable for Series 2017A Notes registered in such names as the Depositary shall direct.

Neither the Company, the Trustee nor any agent of the Company or the Trustee shall have any responsibility or liability for any aspect of the records relating to or payments made on account of beneficial ownership interests in a Global Security or for maintaining, supervising or reviewing any records relating to such beneficial ownership interests.

SECTION 107. Transfer . A Rule 144A Global Note may not be transferred on the Security Register except in compliance with the restrictions on transfer contained in the Rule 144A Legend and upon receipt by the Security Registrar of a completed and executed Transfer Certificate in the form contained in Exhibit A. Prior to the expiration of 40 days beginning on and including the later of (i) the day on which the offering of the Series 2017A Notes commences and (ii) the Original Issue Date (the "Distribution Compliance Period"), a Regulation S Global Note may not be transferred on the Security Register except in compliance with the restrictions on transfer contained in the Regulation S Legend and upon receipt by the Security Registrar of a completed and executed Transfer Certificate in the form contained in Exhibit A hereto. No service charge will be made for any transfer or exchange of Series 2017A Notes, but payment will be required of a sum sufficient to cover any tax or other governmental charge that may be imposed in connection therewith.

The transfer and exchange of beneficial interests in the Global Securities shall be effected through the Depositary, in accordance with this Nineteenth Supplemental Indenture (including applicable restrictions on transfer set forth herein, if any) and the procedures of the Depositary therefor.

Until the expiration of the Distribution Compliance Period, transfers by an owner of a beneficial interest in a Regulation S Global Note to a transferee who takes delivery of such interest through a Rule 144A Global Note will be made only upon receipt by the Trustee of a completed and executed Transfer Certificate in the form contained in Exhibit A hereto from the transferor of the beneficial interest to the effect that such transfer is being made to a person whom the transferor reasonably believes is a qualified institutional buyer (as defined in Rule 144A under the Securities Act) in a transaction meeting the requirements of Rule 144A and the requirements of applicable securities laws of any state of the United States or any other jurisdiction.

Transfers by an owner of a beneficial interest in the Rule 144A Global Note to a transferee who takes delivery through the Regulation S Global Note, whether before or after the expiration of the Distribution Compliance Period, will be made only upon receipt by the Trustee of a Transfer Certificate in the form contained in Exhibit A hereto from the transferor to the effect that such transfer is being made in accordance with Regulation S or Rule 144 under the Securities Act and that, if such transfer is being made prior to the expiration of the Distribution Compliance Period, the interest transferred will be held immediately thereafter through Euroclear Bank S.A./N.V., as operator of the Euroclear System or Clearstream Banking, société anonyme, Luxembourg.

Any beneficial interest in one of the Global Securities that is transferred to a person who takes delivery in the form of an interest in another Global Security will, upon transfer, cease to be an interest in the initial Global Security and will become an interest in the other Global Security and, accordingly, will thereafter be subject to all transfer restrictions, if any, and other procedures applicable to beneficial interests in such other Global Security for as long as it remains such an interest.

Transfers of beneficial interests between a Rule 144A Global Note and a Regulation S Global Note, and other transfers relating to beneficial interests in the Global Securities, shall be reflected by endorsements of the Trustee, as custodian for The Depository Trust Company, on the schedules attached to such Rule 144A Global Note and Regulation S Global Note.

Neither the Trustee, the Security Registrar nor any transfer agent shall have any obligation or duty to monitor, determine or inquire as to compliance with any restrictions on transfer imposed under the Indenture or under applicable law with respect to any transfer of any interest in any Series 2017A Note (including any transfers between or among Depositary participants, members or beneficial owners in any Global Security) other than to require delivery of such certificates and other documentation or evidence as are expressly required by, and to do so if and when expressly required by, the terms of the Indenture, and to examine the same to determine substantial compliance as to form with the express requirements hereof.

Neither the Company nor the Trustee shall have any liability for acts or omissions of the Depositary, for the Depositary records of beneficial interest, for any transactions between the Depositary, any participant member of the Depositary and/or beneficial owner of any interest in any Series 2017A Notes, or in respect of any transfers effected by the Depositary or by any participant member of the Depositary or any beneficial owner of any interest in any Series 2017A Notes held through any such participant member of the Depositary.

The Company shall not be required (a) to issue, register the transfer of or exchange any Series 2017A Notes during a period beginning at the opening of business fifteen (15) days before the date of the mailing of a notice pursuant to Section 1104 of the Original Indenture identifying the serial numbers of the Series 2017A Notes to be called for redemption, and ending at the close of business on the date of the mailing, or (b) to register the transfer of or exchange any Series 2017A Notes theretofore selected for redemption in whole or in part, except the unredeemed portion of any Series 2017A Notes redeemed in part.

SECTION 108. Redemption at the Company's Option. On or after September 30, 2019, the Series 2017A Notes will be subject to redemption, from time to time, at the option of the Company, in whole or in part, on any Interest Payment Date upon not less than 15 nor more than 60 days' notice, at a redemption price equal to 100% of the principal amount of the Series 2017A Notes being redeemed plus accrued and unpaid interest on the Series 2017A Notes being redeemed to the Redemption Date.

If the Redemption Date is not a Business Day, the principal and interest due on that date will be payable on the next succeeding Business Day, and no interest shall accrue for the intervening period.

In the event of redemption of the Series 2017A Notes in part only, a new Series 2017A Note or Notes for the unredeemed portion will be issued in the name or names of the Holders thereof upon the surrender thereof.

The Series 2017A Notes will not have a sinking fund.

Except as otherwise provided herein, notice of redemption shall be given as provided in Section 1104 of the Original Indenture.

Any redemption of less than all of the Series 2017A Notes shall, with respect to the principal thereof, be divisible by $1,000.

SECTION 109. Information to Holders. Upon the request of any Holder, any holder of a beneficial interest in the Series 2017A Notes, or the Trustee (on behalf of a Holder or a holder of a beneficial interest in the Series 2017A Notes), the Company will furnish such information as is specified in paragraph (d)(4) of Rule 144A promulgated under the 1933 Act to Holders (and to holders of beneficial interests in the Series 2017A Notes), to prospective purchasers of the Series 2017A Notes (and of beneficial interests in the Series 2017A Notes) who are qualified institutional buyers or to the Trustee for delivery to such Holder or prospective purchasers of the Series 2017A Notes or beneficial interests therein, as the case may be, unless, at the time of such request, the Company is subject to the reporting requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended.

Delivery of information to the Trustee pursuant to this Section 109 is for informational purposes only and the Trustee’s receipt of such shall not constitute constructive notice of any information contained therein or determinable from information contained therein, including the Company’s compliance with any of its covenants under the Indenture.

ARTICLE 2

MISCELLANEOUS PROVISIONS

SECTION 201. Recitals by Company. The recitals in this Nineteenth Supplemental Indenture are made by the Company only and not by the Trustee, and all of the provisions contained in the Original Indenture in respect of the rights, privileges, immunities, powers and duties of the Trustee shall be applicable in respect of Series 2017A Notes and of this Nineteenth Supplemental Indenture as fully and with like effect as if set forth herein in full.

SECTION 202. Ratification and Incorporation of Original Indenture. As supplemented hereby, the Original Indenture is in all respects ratified and confirmed, and the Original Indenture as supplemented by this Nineteenth Supplemental Indenture shall be read, taken and construed as one and the same instrument.

SECTION 203. Executed in Counterparts. This Nineteenth Supplemental Indenture may be simultaneously executed in several counterparts, each of which shall be deemed to be an original, and such counterparts shall together constitute but one and the same instrument.

SECTION 204. Legends. Except as determined by the Company in accordance with applicable law, each Series 2017A Note shall bear the applicable legends relating to restrictions on transfer pursuant to the securities laws in substantially the form set forth on Exhibit A hereto.

IN WITNESS WHEREOF, each party hereto has caused this instrument to be signed in its name and behalf by its duly authorized officer, all as of the day and year first above written.

THE SOUTHERN COMPANY

By: /s/Art P. Beattie
Art P. Beattie
Executive Vice President and
Chief Financial Officer

WELLS FARGO BANK, NATIONAL
ASSOCIATION, as Trustee

By: /s/Stefan Victory
Stefan Victory
Vice President

EXHIBIT A

FORM OF SERIES 2017A NOTE

[RULE 144A LEGEND FOR USE WITH RULE 144A GLOBAL NOTES]

NEITHER THIS NOTE NOR ANY BENEFICIAL INTEREST HEREIN HAS BEEN REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "1933 ACT"). EACH HOLDER HEREOF, AND EACH OWNER OF A BENEFICIAL INTEREST HEREIN, BY PURCHASING THIS NOTE, AGREES FOR THE BENEFIT OF THE SOUTHERN COMPANY (THE "COMPANY") THAT THIS NOTE MAY NOT BE RESOLD, PLEDGED OR OTHERWISE TRANSFERRED PRIOR TO THE DATE WHICH IS SIX MONTHS (IF ALL APPLICABLE CONDITIONS TO SUCH RESALE UNDER RULE 144 UNDER THE 1933 ACT (OR ANY SUCCESSOR PROVISION THEREOF) ARE SATISFIED) AFTER THE LATER OF THE ORIGINAL ISSUANCE DATE THEREOF, THE ISSUANCE DATE OF ANY SUBSEQUENT ISSUANCE OF ADDITIONAL NOTES OF THE SAME SERIES AND THE LAST DATE ON WHICH THE COMPANY OR ANY AFFILIATE THEREOF WAS THE OWNER OF THIS NOTE OR THE EXPIRATION OF SUCH SHORTER PERIOD AS MAY BE PRESCRIBED BY SUCH RULE 144 (OR SUCH SUCCESSOR PROVISION) PERMITTING RESALES OF THIS NOTE WITHOUT ANY CONDITIONS (THE "RESALE RESTRICTION TERMINATION DATE") OTHER THAN (A)(1) TO THE COMPANY, (2) IN A TRANSACTION ENTITLED TO AN EXEMPTION FROM REGISTRATION PROVIDED BY RULE 144 UNDER THE 1933 ACT (IF AVAILABLE), (3) SO LONG AS THIS NOTE IS ELIGIBLE FOR RESALE PURSUANT TO RULE 144A UNDER THE 1933 ACT ("RULE 144A"), TO A PERSON WHOM THE SELLER REASONABLY BELIEVES IS A QUALIFIED INSTITUTIONAL BUYER WITHIN THE MEANING OF RULE 144A PURCHASING FOR ITS OWN ACCOUNT OR FOR THE ACCOUNT OF A QUALIFIED INSTITUTIONAL BUYER TO WHOM NOTICE IS GIVEN THAT THE RESALE, PLEDGE OR OTHER TRANSFER IS BEING MADE IN RELIANCE ON RULE 144A UNDER THE 1933 ACT (AS INDICATED BY THE BOX CHECKED BY THE TRANSFEROR ON THE CERTIFICATE OF TRANSFER ATTACHED TO THIS NOTE), (4) IN AN OFFSHORE TRANSACTION IN ACCORDANCE WITH RULE 903 OR 904 OF REGULATION S UNDER THE 1933 ACT (AS INDICATED BY THE BOX CHECKED BY THE TRANSFEROR ON THE CERTIFICATE OF TRANSFER ATTACHED TO THIS NOTE), (5) IN ACCORDANCE WITH ANOTHER APPLICABLE EXEMPTION FROM THE REGISTRATION REQUIREMENTS OF THE 1933 ACT (AND BASED UPON AN OPINION OF COUNSEL ACCEPTABLE TO THE COMPANY), OR (6) PURSUANT TO AN EFFECTIVE REGISTRATION STATEMENT UNDER THE 1933 ACT AND (B) IN EACH CASE IN ACCORDANCE WITH ANY APPLICABLE SECURITIES LAWS OF ANY STATE OF THE UNITED STATES. THE FOREGOING RESTRICTIONS ON RESALE WILL NOT APPLY SUBSEQUENT TO THE RESALE RESTRICTION TERMINATION DATE. THE HOLDER HEREOF, BY PURCHASING THIS NOTE, REPRESENTS AND AGREES FOR THE BENEFIT OF THE COMPANY THAT IT IS (i) A QUALIFIED INSTITUTIONAL BUYER WITHIN THE MEANING OF RULE 144A UNDER THE 1933 ACT OR (ii) A NON-U.S. PERSON OUTSIDE THE UNITED STATES WITHIN THE

MEANING OF, OR AN ACCOUNT SATISFYING THE REQUIREMENTS OF, PARAGRAPH (k)(2) OF RULE 902 UNDER REGULATION S UNDER THE 1933 ACT. THE HOLDER OF THIS NOTE ACKNOWLEDGES THAT THE COMPANY OR THE TRUSTEE RESERVES THE RIGHT PRIOR TO ANY OFFER, SALE OR OTHER TRANSFER (1) PURSUANT TO CLAUSE (A)(2) PRIOR TO THE RESALE RESTRICTION TERMINATION DATE TO REQUIRE THE DELIVERY OF AN OPINION OF COUNSEL, CERTIFICATIONS OR OTHER INFORMATION SATISFACTORY TO THE COMPANY AND THE TRUSTEE AND (2) IN EACH OF THE FOREGOING CASES, TO REQUIRE THAT A CERTIFICATE AS TO COMPLIANCE WITH CERTAIN CONDITIONS TO TRANSFER IS COMPLETED AND DELIVERED BY THE TRANSFEROR TO THE COMPANY AND THE TRUSTEE.

[REGULATION S LEGEND FOR USE WITH REGULATION S GLOBAL NOTES]

THE SECURITIES COVERED HEREBY HAVE NOT BEEN REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE “1933 ACT”), AND MAY NOT BE OFFERED OR SOLD WITHIN THE UNITED STATES OR TO, OR FOR THE ACCOUNT OR BENEFIT OF, U.S. PERSONS (I) AS PART OF THEIR DISTRIBUTION AT ANY TIME OR (II) OTHERWISE UNTIL 40 DAYS AFTER THE LATER OF THE DATE OF THE COMMENCEMENT OF THE OFFERING OF THE SECURITIES AND THE DATE OF ORIGINAL ISSUANCE OF THE SECURITIES, EXCEPT IN EITHER CASE IN ACCORDANCE WITH REGULATION S OR RULE 144A UNDER THE 1933 ACT OR ANY OTHER AVAILABLE EXEMPTION FROM REGISTRATION UNDER THE 1933 ACT. TERMS USED ABOVE HAVE THE MEANINGS GIVEN TO THEM BY REGULATION S.

NO. _______

CUSIP NO. ___________________

THE SOUTHERN COMPANY
SERIES 2017A FLOATING RATE SENIOR NOTE
DUE SEPTEMBER 30, 2020

Initial Principal Amount:	$_____________
Regular Record Date:	15th calendar day prior to the applicable Interest Payment Date (whether or not a Business Day)
Original Issue Date:	June 21, 2017
Stated Maturity:	September 30, 2020; provided that if the Stated Maturity is not a Business Day, the principal and interest due on that date will be payable on the next succeeding Business Day, and no interest shall accrue for the intervening period.
Interest Payment Dates:	30 th day of March, June, September and December; provided, however, in the event that any Interest Payment Date (other than the Interest Payment Date that is the Stated Maturity or a Redemption Date) would otherwise be a day that is not a Business Day, the Interest Payment Date will be the next succeeding Business Day
Interest Rate:	LIBOR plus 0.70% per annum, as set on each Interest Determination Date
Authorized Denominations:	$2,000 or any integral multiple of $1,000 in excess thereof

The Southern Company, a Delaware corporation (the “Company,” which term includes any successor corporation under the Indenture referred to on the reverse hereof), for value received, hereby promises to pay to _____________________________________, or registered assigns, the principal sum of ________________________________ DOLLARS ($__________), or such other amount as indicated on the Schedule of Increases or Decreases in Global Security attached hereto as Schedule I, on the Stated Maturity shown above (or upon earlier redemption), and to pay interest thereon from the Original Issue Date shown above, or from the most recent Interest Payment Date to which interest has been paid or duly provided for, quarterly in arrears on each Interest Payment Date as specified above, commencing on September 30, 2017 and on the Stated Maturity (or upon earlier redemption) at the rates per annum determined in accordance with the provisions specified below until the principal hereof is paid or made available for payment and at such rates on any overdue principal and on any overdue installment of interest. The interest so payable, and punctually paid or duly provided for, on any Interest Payment Date (other than an Interest Payment Date that is the Stated Maturity or on a Redemption Date) will, as provided in such Indenture, be paid to the Person in whose name this Note (the “Note”) is registered at the close of business on the Regular Record Date as specified above next preceding such Interest Payment Date, provided that

any interest payable at the Stated Maturity or on any Redemption Date will be paid to the Person to whom principal is payable. Except as otherwise provided in the Indenture, any such interest not so punctually paid or duly provided for will forthwith cease to be payable to the Holder on such Regular Record Date and may either be paid to the Person in whose name this Note is registered at the close of business on a Special Record Date for the payment of such defaulted interest to be fixed by the Trustee, notice whereof shall be given to Holders of Notes of this series not less than 10 days prior to such Special Record Date, or be paid at any time in any other lawful manner not inconsistent with the requirements of any securities exchange, if any, on which the Notes of this series shall be listed, and upon such notice as may be required by any such exchange, all as more fully provided in the Indenture.

The Series 2017A Notes (as defined on the reverse hereof) will bear interest for each Interest Period at a per annum rate determined by the Calculation Agent, subject to the maximum interest rate permitted by New York or other applicable state law, as such law may be modified by United States law of general application. The interest rate applicable during each Interest Period will be equal to LIBOR on the Interest Determination Date for such Interest Period plus 0.70%; provided, that in no event shall the applicable interest rate be less than 0% for any Interest Period. Promptly upon such determination, the Calculation Agent will notify the Company and the Trustee, if the Trustee is not then serving as the Calculation Agent, of the interest rate for the new Interest Period. The interest rate determined by the Calculation Agent, absent manifest error, shall be binding and conclusive upon the beneficial owners and Holders of the Series 2017A Notes, the Company and the Trustee.

“Calculation Agent” means The Wells Fargo Bank, National Association, or its successor appointed by the Company, acting as calculation agent.

“Interest Determination Date” means the second London Business Day immediately preceding the first day of the relevant Interest Period.

“Interest Period” means the period commencing on an Interest Payment Date (or, with respect to the initial Interest Period only, commencing on the Original Issue Date) and ending on the day before the next succeeding Interest Payment Date.

“LIBOR” means, with respect to any Interest Period, the rate (expressed as a percentage per annum) for deposits in U.S. dollars for a three-month period commencing on the first day of that Interest Period and ending on the next Interest Payment Date that appears on Reuters LIBOR01 Page as of 11:00 a.m. (London time) on the Interest Determination Date for that Interest Period. If such rate does not appear on the Reuters LIBOR01 Page as of 11:00 a.m. (London time) on the Interest Determination Date for that Interest Period, LIBOR will be determined on the basis of the rates at which deposits in U.S. dollars for the Interest Period and in a principal amount of not less than $1,000,000 are offered to prime banks in the London interbank market by four major banks in the London interbank market (which may include affiliates of one or more of the underwriters of the Series 2017A Notes) selected by the Calculation Agent (after consultation with the Company), at approximately 11:00 a.m., London time, on the Interest Determination Date for that Interest Period. The Calculation Agent will request the principal London office of each such bank to provide a quotation of its rate. If at least

two such quotations are provided, LIBOR with respect to that Interest Period will be the arithmetic mean of such quotations. If fewer than two quotations are provided, LIBOR with respect to that Interest Period will be the arithmetic mean of the rates quoted by three major banks in New York City (which may include affiliates of one or more of the underwriters of the Series 2017A Notes) selected by the Calculation Agent (after consultation with the Company), at approximately 11:00 a.m., New York City time, on the Interest Determination Date for that Interest Period for loans in U.S. dollars to leading European banks for that Interest Period and in a principal amount of not less than $1,000,000. However, if fewer than three banks selected by the Calculation Agent to provide quotations are quoting as described above, LIBOR for that Interest Period will be the same as LIBOR as determined for the previous Interest Period.

"London Business Day" means a day that is a Business Day and a day on which dealings in deposits in U.S. dollars are transacted, or with respect to any future date are expected to be transacted, in the London interbank market.

"Reuters LIBOR01 Page" means the display designated as Reuters LIBOR01 on the Reuters service (or such other page as may replace the Reuters LIBOR01 Page on that service, or such other service as may be nominated as the information vendor, for the purpose of displaying rates or prices comparable to the London Interbank Offered rate for U.S. dollar deposits).

Payments of interest on this Note will include interest accrued to but excluding the respective Interest Payment Dates. Interest payments for this Note shall be computed and paid on the basis of the actual number of days elapsed over a 360-day year. A "Business Day" shall mean any day other than a Saturday or a Sunday or a day on which banking institutions in New York City are authorized or required by law or executive order to remain closed or a day on which the Corporate Trust Office of the Trustee is closed for business.

Payment of the principal of and interest due at the Stated Maturity or earlier redemption of the Series 2017A Notes shall be made upon surrender of the Series 2017A Notes at the Corporate Trust Office of the Trustee. The principal of and interest on the Series 2017A Notes shall be paid in such coin or currency of the United States of America as at the time of payment is legal tender for payment of public and private debts. Payment of interest (including interest on an Interest Payment Date) will be made, subject to such surrender where applicable, at the option of the Company, (i) by check mailed to the address of the Person entitled thereto as such address shall appear in the Security Register or (ii) by wire transfer or other electronic transfer at such place and to such account at a banking institution in the United States as may be designated in writing to the Trustee at least 16 days prior to the date for payment by the Person entitled thereto.

REFERENCE IS HEREBY MADE TO THE FURTHER PROVISIONS OF THIS NOTE SET FORTH ON THE REVERSE HEREOF, WHICH FURTHER PROVISIONS SHALL FOR ALL PURPOSES HAVE THE SAME EFFECT AS IF SET FORTH AT THIS PLACE.

Unless the certificate of authentication hereon has been executed by the Trustee by manual signature, this Note shall not be entitled to any benefit under the Indenture or be valid or obligatory for any purpose.

IN WITNESS WHEREOF, the Company has caused this instrument to be duly executed under its corporate seal.

Dated:

THE SOUTHERN COMPANY

By: ______________________________

Title:

Attest:

____

Title:

{Seal of THE SOUTHERN COMPANY appears here}

CERTIFICATE OF AUTHENTICATION

This is one of the Senior Notes referred to in the within-mentioned Indenture.

WELLS FARGO BANK, NATIONAL
ASSOCIATION, as Trustee

By: ______________________________
Authorized Officer

(Reverse Side of Note)

This Note is one of a duly authorized issue of Senior Notes of the Company (the "Notes"), issued and issuable in one or more series under a Senior Note Indenture (the "Original Indenture"), dated as of January 1, 2007, as supplemented, including by a Nineteenth Supplemental Indenture dated as of June 21, 2017 (the "Indenture"), between the Company and Wells Fargo Bank, National Association, Trustee (the "Trustee," which term includes any successor trustee under the Indenture), to which Indenture and all indentures incidental thereto reference is hereby made for a statement of the respective rights, limitation of rights, duties and immunities thereunder of the Company, the Trustee and the Holders of the Notes issued thereunder and of the terms upon which said Notes are, and are to be, authenticated and delivered. This Note is one of the series designated on the face hereof as Series 2017A Floating Rate Senior Notes due September 30, 2020 (the "Series 2017A Notes") which is unlimited in aggregate principal amount. Capitalized terms used herein for which no definition is provided herein shall have the meanings set forth in the Indenture.

On or after September 30, 2019, the Series 2017A Notes will be subject to redemption, from time to time, at the option of the Company, in whole or in part, on any Interest Payment Date upon not less than 15 nor more than 60 days' notice, at a redemption price equal to 100% of the principal amount of the Series 2017A Notes being redeemed plus accrued and unpaid interest on the Series 2017A Notes being redeemed to the Redemption Date.

If the Redemption Date is not a Business Day, the principal and interest due on that date will be payable on the next succeeding Business Day, and no interest shall accrue for the intervening period.

In the event of redemption of this Note in part only, a new Note or Notes of this series for the unredeemed portion hereof will be issued in the name of the Holder hereof upon the surrender hereof. The Series 2017A Notes will not have a sinking fund.

If an Event of Default with respect to the Notes of this series shall occur and be continuing, the principal of the Notes of this series may be declared due and payable in the manner, with the effect and subject to the conditions provided in the Indenture.

The Indenture permits, with certain exceptions as therein provided, the amendment thereof and the modification of the rights and obligations of the Company and the rights of the Holders of the Notes of each series to be affected under the Indenture at any time by the Company and the Trustee with the consent of the Holders of not less than a majority in principal amount of the Notes at the time Outstanding of each series to be affected. The Indenture also contains provisions permitting the Holders of specified percentages in principal amount of the Notes of each series at the time Outstanding, on behalf of the Holders of all Notes of such series, to waive compliance by the Company with certain provisions of the Indenture and certain past defaults under the Indenture and their consequences. Any such consent or waiver by the Holder of this Note shall be conclusive and binding upon such Holder and upon all future Holders of this Note and of any Note issued upon the registration of transfer hereof or in exchange hereof or in lieu hereof, whether or not notation of such consent or waiver is made upon this Note.

No reference herein to the Indenture and no provision of this Note or of the Indenture shall alter or impair the obligation of the Company, which is absolute and unconditional, to pay the principal of and interest on this Note at the times, place and rates, and in the coin or currency, herein prescribed.

As provided in the Indenture and subject to certain limitations therein set forth, the transfer of this Note is registrable in the Security Register, upon surrender of this Note for registration of transfer at the office or agency of the Company for such purpose, duly endorsed by, or accompanied by a written instrument of transfer in form satisfactory to the Company and the Security Registrar and duly executed by, the Holder hereof or his attorney duly authorized in writing, together with the completed and executed Transfer Certificate attached hereto (as applicable), and thereupon one or more new Notes of this series, of authorized denominations and of like tenor and for the same aggregate principal amount, will be issued to the designated transferee or transferees. No service charge shall be made for any such registration of transfer or exchange, but the Company may require payment of a sum sufficient to cover any tax or other governmental charge payable in connection therewith.

Prior to due presentment of this Note for registration of transfer, the Company, the Trustee and any agent of the Company or the Trustee may treat the Person in whose name this Note is registered as the owner hereof for all purposes, whether or not this Note be overdue, and neither the Company, the Trustee nor any such agent shall be affected by notice to the contrary.

The Notes of this series are issuable only in registered form without coupons in denominations of $2,000 and any integral multiple of $1,000 in excess thereof. As provided in the Indenture and subject to certain limitations therein set forth, Notes of this series are exchangeable for a like aggregate principal amount of Notes of this series of a different authorized denomination, as requested by the Holder surrendering the same upon surrender of the Note or Notes to be exchanged at the office or agency of the Company.

This Note shall be governed by, and construed in accordance with, the internal laws of the State of New York.

ABBREVIATIONS

The following abbreviations, when used in the inscription on the face of this instrument, shall be construed as though they were written out in full according to applicable laws or regulations:

TEN COM- as tenants in common

TEN ENT- as tenants by the entireties

JT TEN- as joint tenants with right of survivorship and not as tenants in common

UNIF GIFT MIN ACT- _______ Custodian ________
(Cust) (Minor)

under Uniform Gifts to Minors Act

____
(State)

Additional abbreviations may also be used though not on the above list.

FOR VALUE RECEIVED, the undersigned hereby sell(s) and transfer(s) unto

____

(please insert Social Security or other identifying number of assignee)

____

PLEASE PRINT OR TYPEWRITE NAME AND ADDRESS, INCLUDING POSTAL ZIP CODE OF ASSIGNEE

____

____

the within Note and all rights thereunder, hereby irrevocably constituting and appointing

____

____

agent to transfer said Note on the books of the Company, with full power of substitution in the premises.

Dated: ______________________ ___________________________________

____

NOTICE: The signature to this assignment must correspond with the name as written upon the face of the within instrument in every particular without alteration or enlargement, or any change whatever.

TRANSFER CERTIFICATE

In connection with any transfer of any of the Series 2017A Notes evidenced by this certificate [prior to the expiration of the Distribution Compliance Period] [2], the undersigned confirms that such Series 2017A Notes are being:

CHECK ONE BOX BELOW

(1) ☐ exchanged for the undersigned's own account without transfer; or

(2) ☐ transferred to the Company; or

(3) ☐ transferred to a person whom the undersigned reasonably believes is a "qualified institutional buyer" within the meaning of Rule 144A under the Securities Act of 1933, as amended (the "1933 Act"), purchasing for its own account or for the account of a "qualified institutional buyer" to whom notice is given that the resale, pledge or other transfer is being made in reliance on Rule 144A under the 1933 Act; or

(4) ☐ transferred pursuant to an exemption under Rule 144 under the 1933 Act; or

(5) ☐ transferred in an offshore transaction in accordance with Rule 903 or Rule 904 of Regulation S under the 1933 Act; or

(6) ☐ transferred pursuant to another available exemption from the registration requirements of the 1933 Act; or

(7) ☐ transferred pursuant to an effective registration statement under the 1933 Act.

Unless one of the boxes is checked, the Trustee will refuse to register any of the Series 2017A Notes evidenced by this certificate in the name of any person other than the registered Holder thereof; provided, however, that if box (4) or (6) is checked, the Company may require, prior to registering any such transfer of the Series 2017A Notes, such legal opinions, certifications and other information as the Company has reasonably requested to confirm that such transfer is being made pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the 1933 Act, such as the exemption provided by Rule 144 under the 1933 Act; provided, further, that if box (3) is checked, the transferee must certify that it is a qualified institutional buyer as defined in Rule 144A.

Date: ____________________

____
Signature

____
Tax Identification Number

[2] [To be included for Regulation S Global Notes only.]

TO BE COMPLETED BY PURCHASER IF (3) ABOVE IS CHECKED.

The undersigned represents and warrants that it is purchasing this Series 2017A Note for its own account or an account with respect to which it exercises sole investment discretion and that it and any such account is a “qualified institutional buyer” within the meaning of Rule 144A under the 1933 Act, and is aware that the sale to it is being made in reliance on Rule 144A and acknowledges that it has received such information regarding the Company as the undersigned has requested pursuant to Rule 144A or has determined not to request such information and that it is aware that the transferor is relying upon the undersigned’s foregoing representations in order to claim the exemption from registration provided by Rule 144A.

Date: ________________________

____

Signature

NOTICE: If an entity, to be executed by an executive officer.

SCHEDULE I TO GLOBAL SECURITY

The initial amount of the Global Securities evidenced by this certificate is $_______________.

SCHEDULE OF INCREASES OR DECREASES IN GLOBAL SECURITY

The following increases or decreases in this Global Security have been made

Date	Amount of increase in Principal Amount of this Global Security	Amount of decrease in Principal Amount of this Global Security	Principal Amount of this Global Security following each decrease or increase	Signature of authorized signatory of Trustee or Securities Registrar

EXHIBIT B

CERTIFICATE OF AUTHENTICATION

This is one of the Senior Notes referred to in the within-mentioned Indenture.

WELLS FARGO BANK, NATIONAL ASSOCIATION, as Trustee

By: ______________________________
Authorized Officer

CONFIDENTIAL& PROPRIETARY
CONFIDENTIAL TRADE SECRET INFORMATION

Georgia Power Company has requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the Securities and Exchange Commission. Georgia Power Company has omitted such portions from this filing and filed them separately with the Securities and Exchange Commission. Such omissions are designated as "[***]."

AMENDED AND RESTATED SERVICES AGREEMENT

BETWEEN

GEORGIA POWER COMPANY, FOR ITSELF AND AS AGENT FOR OGLETHORPE POWER CORPORATION (AN ELECTRIC MEMBERSHIP CORPORATION) , MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA , MEAG POWER SPVJ , LLC , MEAG POWER SPVM, LLC , MEAG POWER SPVP, LLC , AND THE CITY OF DALTON, GEORGIA, ACTING BY AND THROUGH ITS BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS

AND

WESTINGHOUSE ELECTRIC COMPANY LLC
AND
WECTEC GLOBAL PROJECT SERVICES INC.

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AMENDED AND RESTATED SERVICES AGREEMENT

THIS AMENDED AND RESTATED SERVICES AGREEMENT (“Agreement”) is made and entered into this 20 th day of July, 2017 (“Execution Date”), by and among GEORGIA POWER COMPANY, a Georgia corporation (“GPC”), for itself and as agent for OGLETHORPE POWER CORPORATION (AN ELECTRIC MEMBERSHIP CORPORATION), MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA, MEAG POWER SPVJ, LLC, MEAG POWER SPVM, LLC, MEAG POWER SPVP, LLC, and THE CITY OF DALTON, GEORGIA, ACTING BY AND THROUGH ITS BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS, as “Owners,” and WESTINGHOUSE ELECTRIC COMPANY LLC, a Delaware limited liability company having a place of business in Cranberry Township, Pennsylvania (“Westinghouse”), and WECTEC GLOBAL PROJECT SERVICES INC., a Louisiana corporation having a place of business in Charlotte, North Carolina (“WECTEC”). Westinghouse and WECTEC will be referred to collectively as “Service Provider.” Owners and Service Provider may be referred to individually as “Party” and collectively as the “Parties.”

WITNESSETH:

WHEREAS, Service Provider and GPC, for itself and as agent for the Owners, are parties to that certain Engineering, Procurement, and Construction Agreement dated April 8, 2008, as amended (“EPC Agreement”) to, among other things, design, procure, construct, test, and start up two new AP1000 ® nuclear units, Units 3 and 4, at the Vogtle Electric Generating Plant in Waynesboro, Georgia (“Project”); and

WHEREAS, under the EPC Agreement, Service Provider acted as the prime contractor for engineering, procurement, and construction activities for the Project; and

WHEREAS, on March 29, 2017, Service Provider and certain of its affiliates and subsidiaries commenced cases (“Bankruptcy Cases”) under Chapter 11 of Title 11 of the United States Code before the United States Bankruptcy Court for the Southern District of New York (“Bankruptcy Court”); and

WHEREAS, Service Provider and the Owners entered into an Interim Assessment Agreement dated March 29, 2017 (as amended, the “Interim Agreement”); and

WHEREAS, following rejection of the EPC Agreement and termination of the Interim Agreement, Owners wish for Service Provider to provide certain technical support and construction support services in connection with the continued design, procurement, construction, testing, startup, and initial operation of the Project, and the Parties agree that Service Provider will do so only on a fully cost-reimbursable plus Fee basis, with its liability capped;

WHEREAS, the Parties entered into that certain Services Agreement, dated June 9, 2017 (the “Existing Services Agreement”);

WHEREAS, this Agreement, on the terms and subject to the conditions set forth herein, shall amend and restate, in its entirety, the Existing Services Agreement.

NOW, THEREFORE, in consideration of the premises and the terms and conditions set forth herein, the Parties agree as follows:

ARTICLE 1. DEFINITIONS

1.1 "Affiliates" means, with respect to any Party, any other Person that, as of the Effective Date or at any time thereafter, (a) owns or controls, directly or indirectly, the Party, (b) is owned or controlled by the Party, or (c) is under common ownership or control with the Party, where "own" means ownership of fifty percent (50%) or more of the equity interests or rights to distributions on account of equity of the Party and "control" means the power to direct the management or policies of the Party, whether through the ownership of voting securities, by contract, or otherwise.

1.2 "ASME" means the American Society of Mechanical Engineers.

1.3 "COL" means the combined licenses issued by the NRC pursuant to 10 C.F.R. Part 52 for Vogtle Units 3 and 4, respectively.

1.4 "Corrective Action Program" or "CAP" means measures established to assure that conditions adverse to quality, including, but not limited to, failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. The measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The Corrective Action Program shall comply with, among other things, NEI 08-02, "Corrective Action Processes for New Nuclear Power Plants During Construction" and is part of the Quality Assurance Program as defined in Section 13.1.

1.5 "DCD" means the AP1000 ® Nuclear Power Plant Design Control Document, as certified and approved by the NRC in 10 C.F.R. Part 52 Appendix D.

1.6 "Deliverables" shall have the meaning set forth in Exhibit B (Deliverables).

1.7 "Design Bases" shall have the meaning ascribed to it in 10 C.F.R. § 50.2.

1.8 "Environmental Law" means the Comprehensive Environmental Response, Compensation and Liability Act, 42 U.S.C. § 9601 et seq.; the Resource Conservation and Recovery Act, 42 U.S.C. § 6901 et seq.; the Federal Water Pollution Control Act, 33 U.S.C. § 1251 et seq.; the Clean Air Act, 42 U.S.C. § 7401 et seq.; the Toxic Substances Control Act, 15 U.S.C. §§ 2601 through 2629; the Oil Pollution Act, 33 U.S.C. § 2701 et seq.; the Emergency Planning and Community Right-to-Know Act, 42 U.S.C. § 11001 et seq.; the Safe Drinking Water Act, 42 U.S.C. §§ 300f through 300j; the Endangered Species Act, 16 U.S.C. §§ 1531- 1544 and all Laws (including implementing regulations) of any Government Authority having jurisdiction over the Project addressing the environment, human health, safety, natural resources,

plant and animal species, cultural and archeological resources or the use or release into the environment of any Hazardous Materials.

1.9 "ERA" means the Energy Reorganization Act of 1974, as amended.

1.10 "Facility" means Vogtle Units 3 and 4 and the systems, structures and components that will be utilized by one or both Units.

1.11 "Facility IP" shall have the meaning set forth in Exhibit F (Facility IP License in the Event of a Triggering Event).

1.12 "Facility Purposes" has the meaning set forth in Section 14.4.

1.13 "Fee" has the meaning specified in Exhibit C (Rates and Invoicing).

1.14 "Financing Parties" means the lenders and financing institutions providing construction, interim and/or long-term financing for the Facility or any portion thereof, including any financing in the form of a synthetic lease or leveraged lease, and their assigns and a trustee or agent acting on behalf of the lenders or financing institutions. The U.S. Department of Energy, in its capacity as a guarantor of any indebtedness issued by any Owner, and any trustee or agent acting on behalf of the DOE, shall be deemed "Financing Parties."

1.15 "Fitness for Duty" or "FFD" means the fitness-for-duty programs, developed pursuant to 10 C.F.R. Part 26, that provide reasonable assurance that nuclear facility personnel are trustworthy, will perform their tasks in a reliable manner, are not under the influence of any substance, legal or illegal, that may impair their ability to perform their duties, and are not mentally or physically impaired from any cause that can adversely affect their ability to safely and competently perform their duties.

1.16 "Government Authority" means a federal, state, county, city, local, municipal, foreign or other government or quasi-government authority or a department, agency, subdivision, court or other tribunal of any of the foregoing that has jurisdiction over Owners, Service Provider, the Facility or the activities that are the subject of this Agreement.

1.17 "Governmental Approval" means an authorization, consent, approval, clearance, license, ruling, permit, tariff, certification, exemption, filing, variance, order, judgment, no-action or no-objection certificate, certificate, decree, decision, declaration or publication of, notices to, confirmation or exemption from, or registration by or with a Government Authority relating to the Facility.

1.18 "Georgia PSC Certification Order" means the final, unappealable order issued by the Georgia Public Service Commission with respect to GPC's application for certification of the recovery of the costs of the Units.

1.19 "Hazardous Materials" means each substance designated as a hazardous waste, hazardous substance, hazardous material, pollutant, contaminant or toxic substance under any

Environmental Law and any petroleum or petroleum products, radon, radioactive materials or wastes, asbestos in any form, lead or lead-containing materials, urea formaldehyde foam insulation and polychlorinated biphenyls that have been released into the environment in concentrations or locations for which remedial action is required under any applicable Environmental Law.

1.20 "Intellectual Property" or "IP" shall have the meaning set forth in Exhibit G (IP License).

1.21 "ITAAC" means the NRC inspections, tests and analyses and their associated acceptance criteria which are approved and issued for the Facility pursuant to 10 C.F.R. § 52.97(b).

1.22 "Law" means (a) a constitution, statute, law, rule, regulation, code, treaty, ordinance, judgment, decree, writ, order, concession, grant, franchise, license, agreement, directive, guideline, policy, requirement, or any other governmental restriction or any similar form of decision of or determination by, or any binding interpretation or administration of any of the foregoing, by a Government Authority, whether now or hereafter in effect and (b) requirements or conditions on or with respect to the issuance, maintenance or renewal of a Governmental Approval or applications therefor, whether now or hereafter in effect, including, without limitation, the Licensing Basis, the Design Bases for the Facility and the COL.

1.23 "Licensed IP" shall have the meaning set forth in Exhibit G (IP License).

1.24 "Licensing Basis" means the ITAAC, COL, UFSAR (including, but not limited to, the plant-specific design-basis information defined in 10 C.F.R. § 50.2 documented therein) and other NRC rules, regulations, and requirements applicable to the Facility, including, but not limited to, the licensee's written commitments for ensuring compliance with and operation within applicable NRC requirements and the Facility-specific design basis (including, but not limited to, all modifications and additions to such commitments that are docketed and in effect over the term of the COL). The Licensing Basis includes orders, license conditions, exemptions, and technical specifications.

1.25 "Loan Guaranty Agreements" means the respective Loan Guarantee Agreements between the U.S. Department of Energy, as Guarantor, and MEAG, OPC, and GPC, respecting the Project.

1.26 "NRC" means the United States Nuclear Regulatory Commission.

1.27 "Nuclear Safety Culture" means the core values and behaviors resulting from a collective commitment by leaders and individuals to emphasize safety over competing goals to ensure protection of people and the environment, as defined in the NRC's Safety Culture Policy Statement, 76 Fed. Reg. 34773 (June 14, 2011).

1.28 " OSHA " means Occupational Safety and Health Administration.

1.29 "OSHA of 1970" means Occupational Safety and Health Act of 1970, as amended .

1.30 "OSHA Log" means OSHA's Form 300, Log of Work-Related Injuries and Illnesses, required to be maintained pursuant to 29 C.F.R. § 1904.

1.31 "OSHA Standards" means the OSHA and regulatory standards or state plan equivalent.

1.32 "Owner Persons Indemnified" shall have the meaning set forth in Article 16.

1.33 "Owners" means, collectively, GPC, OGLETHORPE POWER CORPORATION (AN ELECTRIC MEMBERSHIP CORPORATION), an electric membership corporation formed under the laws of the State of Georgia ("OPC"), MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA, a public body corporate and politic and an instrumentality of the State of Georgia, MEAG POWER SPVJ, LLC, MEAG POWER SPVM, LLC, MEAG POWER SPVP, LLC, each a Georgia limited liability company ("MEAG"), and THE CITY OF DALTON, GEORGIA, an incorporated municipality in the State of Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners.

1.34 "Owners' Authorized Representative" means the Person who Owners designate in writing to act on behalf of Owners under this Agreement.

1.35 "Ownership Agreement" means Plant Alvin W. Vogtle Additional Units Ownership and Participation Agreement dated April 21, 2006, as amended.

1.36 "Person" means an individual, corporation, company, partnership, joint venture, association, limited liability company, trust, unincorporated organization, Government Authority or other entity.

1.37 "Prime Rate" means, as of a particular date, the prime rate of interest as published on that date in *The Wall Street Journal* , and generally defined therein as "the base rate on corporate loans posted by at least 75% of the nation's 30 largest banks."

1.38 "Project Controls" refers to those processes and work activities (e.g., scheduling, planning, cost control, coordination, etc.) performed in the course of construction management of the Project.

1.39 "Project Schedule" means the integrated Project Schedule for the Project.

1.40 "QA" means quality assurance.

1.41 "Recoverable Costs" means the following: cancelation costs for all subcontracts and purchase orders listed on Exhibit H (Subcontracts and Purchase Orders) and subcontracts and purchase orders approved by Owners and executed by Service Provider after the Effective Date, demobilization costs, and other direct out-of-pocket costs that are permitted to be recovered by Service Provider under this Agreement and that are actually incurred by the Service

Provider. For the avoidance of doubt, the definition of "Recoverable Costs" does include employee severance costs actually incurred and that are consistent with the Westinghouse and WECTEC severance programs that were effective immediately prior to the Westinghouse bankruptcy. The definition of "Recoverable Costs" does not include liabilities or damages arising from or related to Service Provider's terminating or releasing employees as a result of Owners' suspension or termination of this Agreement or Owners' reduction, suspension or termination of Services under Section 4.3(b) (Changes to the Scope of Services After the Transition Period.)

1.42 "Representatives" means officers , directors, employees, members, or other authorized agents.

1.43 "Safety Program" means the comprehensive safety program that governs all of Service Provider's activities at the Site in connection with its performance of the Services.

1.44 "Services" means all services the Service Provider is obligated to perform pursuant to this Agreement.

1.45 "Site" means the premises (or portion thereof) owned or leased by Owners on which the Facility is or will be located, including, but not limited to, construction laydown areas. "Site" shall not include the portions of the Vogtle site dedicated solely to Vogtle Units 1 and 2, except to the extent such portions are needed for access, ingress, egress, or will otherwise be impacted by construction or operation of the Facility.

1.46 "SNC" means Southern Nuclear Operating Company, Inc.

1.47 "Third Party" means a Person other than Owners, Service Provider, SNC or any of their Affiliates or employees .

1.48 "UFSAR" means the Vogtle Units 3 and 4 Updated Final Safety Analysis Report, as amended and updated from time to time.

1.49 "Unit" or "Units" means the electric generating plants, utilizing the AP1000 ® standard design as certified by the NRC in Appendix D to 10 C.F.R. Part 52, that are to be constructed and operated as either Vogtle Unit 3 or Vogtle Unit 4.

ARTICLE 2. INTERPRETATION

2.1 Titles, headings, and subheadings of the various articles and paragraphs of this Agreement are used for convenience only and shall not be deemed to be a part thereof or be taken into consideration in the interpretation or construction of this Agreement.

2.2 Words importing the singular only shall also include the plural and vice versa where the context requires. Words in the masculine gender shall be deemed to include the feminine gender and vice versa.

2.3 Unless otherwise stated or the context otherwise requires, any reference to a document shall mean such document as amended, supplemented or otherwise modified and in effect from time to time.

2.4 Unless otherwise stated, any reference to a party shall include its successors and permitted assigns, and any reference to a Government Authority shall include an entity succeeding to its functions.

2.5 Wherever a provision is made in this Agreement for the giving of notice, consent, agreement or approval by a person, such notice, consent, agreement or approval shall be in writing, and the words “notify” and “agreement” shall be construed accordingly.

2.6 This Agreement and the documentation to be supplied hereunder shall be in the English language.

2.7 All monetary amounts contained in this Agreement refer to the currency of the United States unless otherwise specifically provided.

2.8 A reference contained herein to this Agreement or another agreement shall mean this Agreement or such other agreement, as they may be amended or supplemented, unless otherwise stated.

2.9 Words and abbreviations not otherwise defined in this Agreement which have well-known nuclear industry meanings in the United States are used in this Agreement in accordance with those recognized meanings.

2.10 Neither Service Provider nor Owners shall assert or claim a presumption disfavoring the other by virtue of the fact that this Agreement was drafted primarily by the other, and this Agreement shall be construed as if drafted jointly by Owners and Service Provider and no presumption or burden of proof will arise favoring or disfavoring a Party by virtue of the authorship of any of the provisions of this Agreement. Any rule of construction to the effect that ambiguities are to be resolved against the drafting party shall not be applied in the interpretation of this Agreement.

2.11 The word “hereby,” “herein,” “hereunder” or any other word of similar meaning refers to the entire document in which it is contained.

2.12 A reference to an Article includes all Sections and Subsections contained in such Article, and a reference to a Section or Subsection includes all subsections of such Section or Subsection including all exhibits referenced therein.

2.13 All exhibits referred to in, and attached to, this Agreement are hereby incorporated herein in full by this reference.

ARTICLE 3. TERM; CONDITIONS PRECEDENT

3.1 Effective Date; Term. Except as provided in Section 3.4, this Agreement shall become effective upon the satisfaction of the Conditions Precedent in Section 3.2 (such date being the "Effective Date") and, unless earlier terminated in accordance with the provisions of this Agreement, shall remain in full force and effect for a term ending upon the completion of startup and testing and the commencement of sale of electricity of both Units.

3.2 Conditions Precedent. Except as provided in Section 3.4, this Agreement shall not be binding unless and until each of the following conditions are satisfied ("Conditions Precedent"):

(a) Service Provider has rejected the EPC Agreement;

(b) Service Provider has obtained approval to enter into this Agreement from its Debtor-in-Possession lender;

(c) Service Provider has obtained an order from the Bankruptcy Court approving Service Provider's rejection of the EPC Agreement and execution of this Agreement;

(d) Owners have obtained approval of this Agreement by the Department of Energy in accordance with the terms of the Loan Guaranty Agreements; and

(e) Service Provider has obtained approval for this Agreement from its Boards of Directors.

3.3 Efforts to Satisfy Conditions. Commencing on the Execution Date, Service Provider and Owners shall use reasonable efforts to cause the satisfaction of the Conditions Precedent.

3.4 Failure of Conditions Precedent. If for any reason the Conditions Precedent are not satisfied by sixty (60) days from the Execution Date, this Agreement shall be deemed null and void unless the time period is extended by mutual agreement of the Parties. At any time, if the Parties agree in writing that one of the Conditions Precedent cannot be satisfied, this Agreement shall be deemed null and void upon the date of the Parties' written agreement.

3.5 Effect of Prior Project Agreements. As of the Effective Date, all ongoing work performed by Service Provider in connection with the Project, regardless of whether such work was previously governed by the EPC Agreement or the Interim Agreement, shall be exclusively governed by this Agreement. Nothing in this Agreement shall constitute an amendment to, modification of or novation of the EPC Agreement. This Agreement is an independent agreement between Service Provider and Owners. Nothing in this Agreement shall constitute a waiver of any Party's claims or right to make a claim or any Party's defenses under the EPC Agreement or otherwise.

ARTICLE 4. SCOPE OF WORK

4.1 Transfer of Control of Project. On the Effective Date, Service Provider shall transfer and Owners will assume control of the Site and project-level direction and control of the work required to complete the Facility, with ultimate decision-making and direction of all work residing in Owners subject to the terms of Article 13. For a period of ninety (90) days beginning on the Effective Date, Service Provider will provide engineering, procurement, and construction support services consistent with work currently being performed by Service Provider in connection with the Project, except as otherwise directed by Owners or agreed upon by the Parties (the "Transition Period"). During the Transition Period, Service Provider will support the transition of responsibilities to Owners or their designees, as directed, as efficiently and promptly as possible.

(a) Access and Resource Commitment. Service Provider shall (i) make commercially reasonable efforts to maintain current staffing and resource levels, except as expressly authorized by Owners with respect to transferred responsibilities and the process described in Section 4.1(e) (Staffing and Resource Assessment); (ii) maintain Owners' access to on-Site and off-Site facilities, construction equipment, temporary construction facilities and systems, and materials to support continuation of work on the Project and the transition of Project Controls to Owners; and (iii) to the extent required under Section 4.1(f), maintain and provide Owners access to Service Provider's IT network (on-Site and off-Site) in order to support continuation of work on the Project and transition of Project Controls to Owners. Owners agree to comply with Service Provider's applicable Westinghouse policies required for infrastructure access and end use any time Owners access Service Provider's IT network, provided that Service Provider will provide a copy of such policies to Owners on a timetable that supports Owners' access. Service Provider warrants that it will not apply such policies to Owners in a manner that will unreasonably inhibit Owners' access to Service Provider's IT network as contemplated under this Agreement, or cause Service Provider to fail to provide the access otherwise required under this Agreement. Service Provider shall not amend any such policies in a manner that will unreasonably inhibit Owners' access to Service Provider's IT network as contemplated under this Agreement or cause Service Provider to fail to provide the access otherwise required under this Agreement.

(b) Transfer of Project Controls. Service Provider will support transition of the Project Schedule and Project Controls functions to Owners. The current integrated Project Schedule will be transferred in its native format (e.g., XER files). Following the transfer of the Project Schedule and Project Controls to Owners, Service Provider will provide ongoing Project Controls information to Owners to enable Owners to track the Project Schedule and costs.

(c) Subcontracts. Service Provider shall assume and assign to Owners or their designee, and Owners or their designee shall assume, the contracts listed on Exhibit H, Part A; provided that Owners may elect, by giving written notice thereof to Service Provider within a reasonable time prior to the entry of an order authorizing the

assumption and assignment of such contracts, not to accept any such contract, whereupon such contract will be removed from Exhibit H, Part A. Service Provider shall assume the contracts listed on Exhibit H, Part B as amended to include Owners as parties thereto, including the ability to exercise the rights and remedies thereunder and with a direct obligation to pay the counterparty for all liabilities thereunder; provided that Owners may elect, by giving written notice thereof to Service Provider within a reasonable time prior to the entry of an order authorizing the assumption of such contracts, not to have the Service Provider assume any such contract, whereupon such contract will be removed from Exhibit H, Part B. Owners shall be responsible for any amount required to be paid in order to assume such contracts. Owners agree to take such actions as may be required to obtain Bankruptcy Court approval of such assumptions. The terms "subcontracts" and "contracts," as used within this Section 4.1(c), include and refer to subcontracts and purchase orders as listed on Exhibit H.

(d) Refinement of Services, Deliverables, and Schedule. During the Transition Period, Owners and Service Provider will further define (i) the Services that Service Provider will perform, (ii) division of responsibilities, (iii) the Deliverables; and (iv) the schedule for completion of Services and delivery of Deliverables to support the updated Project Schedule that will be developed by Owners with Service Provider's input. The Services and Deliverables defined in accordance with this Section 4.1 will be consistent with the high-level descriptions of Services and Deliverables set forth in Exhibit A (Services and Division of Responsibility) and Exhibit B (Deliverables) and any other applicable requirements in this Agreement.

(e) Staffing and Resource Assessment.

(i) Service Provider will support Owners' identification of on-Site and off-Site personnel, facilities, equipment, and infrastructure needed to support completion of the Project.

(ii) Throughout the term of this Agreement, Owners may, at Owners' election, subject to applicable laws, rules and regulations, remove personnel from the Site for cause, and with reasonable notice where practicable. Owners may request relocation of Service Provider's personnel to the Site, subject to Service Provider's and the employee's consent. In the case of relocation, Owners shall be responsible for reasonable relocation expenses (not to include any markup or additional fee).

(iii) Service Provider and Owners will work together to adjust current staffing to levels necessary to perform the Services under this Agreement. Owners shall not be responsible for employee severance or other employee separation costs, liabilities, or damages that result in any way from the staff reductions made during the Transition Period.

(iv) Certain of Service Provider's personnel will work at the direction and control of Owners' personnel (such Services referred to herein as the "Secondment Services"). The Secondment Services will be governed by the terms and conditions of a Staff Augmentation Agreement between Service Provider and Owners, a form of which is attached hereto as Exhibit D (Form of Staff Augmentation Agreement).

(v) Owners will have the right to offer employment to, hire, or offer another contractual arrangement to Service Provider's employees and contract staff on-Site (subject to prior employment-related agreements between Service Provider and such personnel). Owners will have the right to offer employment to, hire, or offer another contractual arrangement to Service Provider's employees and contract staff not working on-Site (subject to prior employment-related agreements between Service Provider and such personnel) only with the consent of Service Provider, which shall not be unreasonably withheld.

(vi) The terms of this Section 4.1(e) shall be effective during and after the Transition Period.

(f) Access to Project Management/Project Controls Information . Service Provider will make available and deliver as necessary to Owners in electronic format (where possible) data, documentation, and applications (including input files) necessary to support transition of the project management and the discrete scopes of work to be transferred to Owners. The information and data available to Owners will be that data and information required for Owners to (1) evaluate the status of the Project and work necessary for completion of the Project, (2) assume responsibility for scope previously performed by Service Provider (including historical information), and (3) perform project management functions. For the software applications required to fulfill items (1), (2), and (3) above, subject to applicable license restrictions, Service Provider will provide input files and data upon request and will work with Owners to evaluate which applications will be maintained by Owners for the balance of the Project and which will be maintained by Service Provider on Owners' behalf (and with full Owners access). Except where unavailable, Service Provider will provide all information and data in the existing file format(s) used by the Service Provider where such format(s) is required to enable Owners' use as contemplated herein. If such file format(s) is unavailable, Service Provider will work with Owners to provide information and data in a format that enables Owners' use as contemplated herein. At Owners' election and expense, this information and any other documentation/records agreed upon by the Parties will be transferred to a single Site document management system maintained by Service Provider or to Owners' document management systems (e.g., CIMS, Documentum). The terms of this Section

4.1(f) shall continue after the Transition Period as necessary for Owners to complete the Project.

(g) Transfer of Program Responsibility . Service Provider will support the transition of control of the Site and the primary responsibility for the following Site-based programs to Owners: access; security; Fitness For Duty; Employee Concerns Program; communications; project accounting and finance; and such other safety, regulatory, or administrative programs as mutually agreed by the Parties. Service Provider will support transition to a single PI & CAP for the Site, which transition will include the development by the Parties of an interface protocol between Service Provider's existing PI & CAP and Owners' existing PI & CAP. The interface protocol will control, at a minimum, the provision of PI & CAP related documentation from Service Provider to Owners, the treatment of any existing open issues within Service Provider's PI & CAP respecting activities which are not Services under this Agreement but nonetheless relate to the Site, and the systems and infrastructure which will be used for the single PI & CAP. Work performed by Service Provider under this section 4.1(g) is reimbursable.

(h) Transfer of Regulatory Permits . During the Transition Period, the Parties will identify the permits held by Service Provider that Owners require to complete the Project, and Service Provider will facilitate the transfer of those regulatory permits to Owners' or Owners' designee that are required to complete the Project.

(i) Insurance . Service Provider will provide a list of existing insurance policies related to the Project, facilities, and equipment within thirty (30) days of the Effective Date and maintain such policies until at least sixty (60) days after the Effective Date. Service Provider will support Owners' efforts to obtain insurance coverage formerly held by Service Provider. Prior to cancellation of any existing insurance policies, Service Provider will provide prompt notice to Owners and at least within ten (10) days of knowledge that cancellation will occur.

(j) Service Provider will support other transition efforts reasonably requested by Owners, including but not limited to regulatory compliance (including but not limited to Georgia Public Service Commission and Securities Exchange Commission reporting or approval requirements), and coordination and cooperation with subcontractors, vendors, suppliers, and consultants.

(k) Service Provider may sell and Owners may purchase certain Service Provider facilities and/or construction equipment at the prices established by an independent valuation company mutually agreed upon by the Parties. Commencing on the Effective Date, Owners will lease certain construction equipment consistent with the terms of Exhibit C (Rates and Invoicing), subject to Owners' election to stop using such equipment at any time during the term of this Agreement.

4.2 Scope of Services. Service Provider will provide mutually agreed engineering, procurement, and construction support services, the categories of which are set forth in Exhibit A (Services and Division of Responsibility), as refined during the Transition Period, or otherwise agreed upon by the Parties.

4.3 Changes to the Scope of Services after the Transition Period.

(a) Owners may desire additions to the scope of Services. Service Provider agrees to consider, in accordance with this Agreement, additions to the scope of Services which are related to the Services for the Project and which do not materially affect the nature of the Services or resource requirements of Service Provider.

(b) Owners, in their sole discretion, shall have the right to reduce or terminate certain Services or portions thereof at any time for their convenience by providing written notice to Service Provider at least fifteen (15) days in advance of the date of termination or other minimally necessary time period required to comply with the WARN Act, as measured from the date of written notice of termination, with respect to employees who are not performing Secondment Services. Following such notice period, Service Provider shall require its employees and subcontractors to cease work thereon, except to the extent otherwise required by the notice itself or by industry safety practices or applicable law, rules or regulations. Owners shall be obligated to pay amounts due, in accordance with Exhibit C (Rates and Invoicing) herein, for Services performed prior to Owners' reduction notice and for any Recoverable Costs associated with such reduction or termination.

(c) Service Provider will not perform Services that it reasonably determines to be new or different or beyond those set forth herein and in Exhibit A (Services and Division of Responsibility) without prior written authorization from Owners' Authorized Representative. To establish authorization for extra compensation for changes in the scope of Services, Service Provider will submit to Owners, in advance of performing the new or different Services, a proposal for the new or different Services, and will submit therewith such cost and schedule information as reasonably required for Owners to evaluate the proposal. Before beginning the new or different Services, Service Provider must secure written authorization from Owners. Service Provider agrees that it will not knowingly make any Claim for payment for new or different Services that Service Provider knew were not authorized in writing by Owners in advance of commencement of the performance of such Services.

4.4 Schedule. Service Provider shall endeavor to perform Services under this Agreement in a timely manner in order to support the Project Schedule. However, as provided for in this Agreement, Owners have the responsibility for the Project Schedule, and Service Provider shall have no liability for Project delays, costs, claims, damages, or losses arising from delays to the Project Schedule. Upon becoming aware that any Services are expected to be completed more than thirty (30) days after the projected date set forth in the Project Schedule, Service Provider will notify Owners in writing of their Service affected and the cause. Service

Provider agrees to make reasonable efforts to comply with Owners' requests to accelerate or recover the Project Schedule.

4.5 Qualification of Service Provider Personnel. Service Provider shall be properly licensed to perform that portion of the Services which require a professional license by law (e.g., engineering design work that must be performed by a licensed professional engineer) and shall be authorized and qualified to do business in all governmental jurisdictions in which the Services are to be performed and will maintain such licenses and qualifications as long as reasonably required to perform the Services. Upon reasonable advance written request of Owners, Service Provider shall furnish to Owners such evidence as Owners may reasonably require relating to Service Provider's qualifications. The Parties agree that (1) Service Provider is not to be considered the constructor of the Project or otherwise responsible for the supervision of the construction of the Project, (2) that Service Provider may not be licensed as a contractor under the laws of the State of Georgia, (3) the Services being rendered under this Agreement do not constitute construction services under Georgia law, (4) the Services do not require a contractor's license under Georgia law, and (5) Owners are not relying on Service Provider for any contractor license.

4.6 Subcontractors. The Services to be performed by Service Provider hereunder shall not be subcontracted nor shall Service Provider procure consultants or other outside services and facilities without the prior written approval of Owners, which Owners may withhold or provide in their discretion. Notwithstanding the foregoing, Service Provider may subcontract its Services in whole or in part to an Affiliate of Service Provider without the prior approval of Owners; provided, however, with the exception of Mangiarotti, WesDyne, and Nuclear Parts Organization ("NPO"), any Services performed by an Affiliate of Service Provider shall be subject to the same pricing terms contained in Exhibit C (Rates and Invoicing) as if Service Provider had performed such Services directly. Owners will incur no duplication of costs or multiple markups as a result of any subcontract. With regard to Mangiarotti, WesDyne, and NPO, such Affiliates will be treated as third party subcontractors, and Owners shall have review and approval rights with regard to these subcontracts.

4.7 Payment to Subcontractors and Vendors; No Liens. Service Provider shall be solely responsible for paying the subcontractors and vendors it engages on the Project. Service Provider shall obtain interim and final lien waivers in the forms provided by Owners from subcontractors and vendors. Service Provider shall provide Owners with copies of the lien waivers upon request. Service Provider shall notify Owners within five (5) days of receipt of knowledge of any liens filed against, or threatened to be filed against, the Facility, Site and/or equipment.

4.8 Support for Governmental Hearings. Service Provider understands and acknowledges that as a result of its performance of this Agreement and the special knowledge it possesses, and in order to defend and explain the decisions, procedures and standards applicable to its furnishing or performing the Services, Service Provider may be called upon to appear at governmental and other hearings. At Owners' expense, including but not limited to the cost of Service Providers' reasonable legal fees, Service Provider agrees that it will appear in such

hearings when requested by GPC or Owners. At Owners' expense, Service Provider will also assist GPC or Owners in the preparation of testimony, reports, or other documents required in any non-adverse lawsuits or governmental or other hearings when called upon to do so by GPC or Owners as part of the Services.

ARTICLE 5. OWNERS' RESPONSIBILITIES AND RIGHTS; OVERSIGHT OF SERVICES

5.1 Independent Contractor . In its performance under this Agreement, Service Provider is and will at all times act as an independent contractor. Subject to the requirements of this Agreement and Owners' ultimate direction of the work required to complete the Facility, Service Provider will be free to perform the obligations of this Agreement by such methods and in such manner as Service Provider may choose, furnishing necessary labor, tools, equipment and materials, and taking the requisite steps to perform the Services appropriately and safely, having supervision over and responsibility for the safety and health of its Representatives while on Owners' premises. Service Provider shall maintain control over and responsibility for its offsite tools, equipment and materials. No partnership, joint venture, agency or employment relationship is created by this Agreement, and Service Provider is not and will not act as an agent or employee of Owners except as required and designated by Owners for procurement. Service Provider's Representatives have no right to participate in any of Owners' employee benefit plans, including but not limited to the provision of health insurance under the Patient Protection and Affordable Care Act of 2010 ("ACA"), as a result of providing the Services. Service Provider shall be solely responsible for (i) payment of all compensation to its employees, (ii) the withholding of federal, state, and local taxes from such compensation and the payment of all such withheld amounts to the appropriate agencies or authorities, (iii) payment to the appropriate agencies or authorities of state unemployment insurance, federal unemployment insurance, FICA and state disability insurance, (iv) paying workers' compensation insurance, and (v) providing the workers with all necessary and appropriate benefits including, without limitation, any health and welfare coverage required under applicable law, including, without limitation, the Health Insurance Portability and Accountability Act of 1996, as amended or revised ("HIPAA") or the ACA or other applicable federal and state health care requirements.

5.2 Appointment of Agents . Owners have appointed GPC as their agent for all purposes under this Agreement pursuant to the Ownership Agreement, with the power and authority to bind Owners to their obligations herein. All obligations required under this Agreement to be fulfilled by the Owners will be performed by or at the direction of GPC, as agent for the Owners. Copies of the Ownership Agreement have been provided to and received by Service Provider. Owners will not materially change (in terms of the effect of any change on the agent's authority with respect to this Agreement) the agency authority granted to GPC (or a successor agent) under the Ownership Agreement without Service Provider's prior written approval not to be unreasonably withheld. GPC, acting for itself and as agent for the other Owners, has appointed SNC as agent for the implementation and administration of this Agreement. SNC is the exclusive licensed operator of Vogtle Units 1 and 2 and is the licensed operator of the Facility having exclusive control over licensed activities at the Facility.

5.3 Owners' Authorized Representative(s). Owners shall appoint Owners' Authorized Representative(s) (and shall have the right to appoint a successor or replacement Owners' Authorized Representative(s)) with whom Service Provider may consult at all reasonable times and whose written instructions, requests and decisions shall be binding upon Owners as to all matters pertaining to this Agreement. Service Provider shall have the right to rely upon a communication from Owners' Authorized Representative(s) as a communication on behalf of all of the Owners and shall not rely upon any instruction or direction issued by any other representatives of Owners other than Owners' Inspector as provided in Section 5.4.

5.4 Owners' Inspector. Owners reserve the right, but shall not be obligated, to appoint inspectors to follow the progress of the Services provided by subcontractors to the Service Provider (each, an "Owners' Inspector"). Owners' Inspectors shall be granted access to the Services being performed at vendor facilities as allowed in the respective subcontract or as required by law, and being performed at Service Provider facilities (not the Site) as reasonably requested and agreed to by Service Provider. Such access shall not be conditioned on Owners or Owners' Inspector waiving the right to reasonably safe access and accommodations. Owners may, but are not obligated to, authorize an Owners' Inspector to stop work, provide direction to Service Provider, or take other actions which are the right or responsibility of Owners under this Agreement. Owners will notify Service Provider in writing of the appointment of any Owners' Inspector and the scope of the Owners' Inspector's authorization to bind Owners. All expenses incurred by Service Provider in connection with complying with the directives of Owners' Inspector pursuant to this Section 5.4 shall constitute actual costs. Service Provider will in no event be considered in breach of any other provision of this Agreement due to its compliance with the directions of Owners' Inspector unless such directions are known to the Service Provider to be outside the scope of the Owners' Inspector's ability to bind Owners.

5.5 Project Metrics. Service Provider will provide information reasonably requested by Owners to enable Owners to evaluate applicable and relevant schedule and cost information for the Project. Whether or not a request has been made by Owners, Service Provider will promptly notify Owners of any event or circumstance of which Service Provider becomes aware which has a material adverse effect on the performance, cost or schedule of completion of the Services. Such project metric documentation and services include, but are not limited to, the following:

(a) Monthly Status Reports. On or before the tenth (10th) day of each month, Service Provider shall submit monthly Project reports in a form including such information as reasonably requested by Owners.

(b) Project Controls Information. Service Provider will provide all schedule and cost information in its possession and reasonably requested by Owners to enable Owners to track Project cost and schedule information.

(c) Schedule and Budgeting Plans. Thirty (30) days prior to the beginning of a calendar quarter, Service Provider will provide good faith estimated schedule information and cost-breakdowns, including supporting information as reasonably requested by Owners, for Services expected to be performed during the immediately

forthcoming quarter. Such estimates shall be broken down into specific categories of Services as reasonably directed by Owners. Within fifteen (15) days of receipt of Service Provider's estimate, Owners may, with respect to Services in the immediately forthcoming quarter: (i) issue a hold on some or all Services (provided that Owners continue to pay Service Provider for all resources dedicated to the Project and affected by the hold period); or (ii) establish a budget cap applicable to the Services or a portion of the Services. Service Provider agrees that it will take commercially reasonable actions to avoid expending or incurring more than any Owner-issued budget cap, except with Owners' prior written approval.

5.6 Owners' Access and Oversight Rights.

(a) In accordance with facility protocol and during reasonable times, Owners will have the right to have its personnel or other representatives (including Third Parties) oversee the performance of the Services in order to determine that the Services comply with the requirements of this Agreement and also to determine that the Services will be performed at a rate that is consistent with or as provided in the Project Schedule. Owners' oversight shall not be deemed to: (i) be supervision by Owners of Service Provider; or (ii) relieve Service Provider of any responsibility for performing the Services in accordance with this Agreement. Owners may report to Service Provider any unsafe or improper conditions or practices observed at the job site for action by Service Provider in correction or enforcement.

(b) Upon receipt of reasonable notice, Owners shall have reasonable access to applicable parts of Service Provider's and/or its subcontractors' facilities engaged in performance of the Services, wherever located, at reasonable times and subject to the reasonable requirements of Service Provider or its subcontractors, and as necessary to enable Owners to monitor the performance of Services.

5.7 Owners' Approval Rights. Service Provider shall obtain Owners' written approval (which may be provided by Owners' Authorized Representative), which Owners may withhold or provide in their sole discretion, prior to taking any of the following actions:

(a) any change in the design of the Facility, based on an approval process to be defined by the Owners, with support of the Service Provider, to ensure effective control of design and execution of the work. Such process shall include definition of how approval shall be documented and recorded, as well as appropriate thresholds for approval requirements;

(b) any change in the means of performing the Services that will require a change to the Licensing Basis (regardless of whether such licensing change requires NRC approval); or

(c) modifying the means, methods, or schedule for Services such that Service Provider knows that the cost to Owners for the Services will materially increase.

5.8 Right to Stop Work. Owners reserve the right to stop performance of any portion of the Services for any or no reason by providing Service Provider with a written stop work order from Owners' Authorized Representative, provided that Owners continue to pay Service Provider for the resources to the extent allocated to the Project and directly affected by the stop work order, and the payment amount shall be commensurate with the percentage of allocation.

5.9 Removal of Personnel. Subject to applicable laws, rules and regulations, Owners, for reasonable cause, have the right to require Service Provider to remove any employee, subcontractor, or subcontractor employee from the Site or from performing Services hereunder. Owners shall provide Service Provider the basis for the removal.

5.10 Not Exclusive Dealings Agreement. This Agreement is not intended to be and shall not be construed to be an exclusive dealings agreement between Owners and Service Provider. Owners shall at all times, in their sole discretion, be free to self-perform any Services or have such Services performed by another party subject to and consistent with the IP licensing agreements in Exhibits F (Facility IP License in the Event of a Triggering Event) and G (IP License), provided that any associated reduction in Services will be only as provided in Section 4.3(b).

5.11 Safeguards Information; Security Related Information.

(a) To the extent not previously provided, Owners shall review and approve all Service Provider Safeguards Information ("SGI") and Security Related Information ("SRI") control and access procedures for the Project and revisions and training requirements that could impact performance of Owners' SGI activities prior to issuance or implementation. Service Provider shall perform a 100% Owners' SGI inventory/accountability check annually. Notification shall be given to Owners prior to start of the inventory/accountability checks, and results from those checks shall be formally reported to Owners.

(b) Service Provider will maintain all SGI and SRI contained in Facility-related documentation and materials retained by Service Provider in accordance with applicable NRC regulatory requirements.

ARTICLE 6. IP DELIVERABLES

6.1 Service Provider IP Deliverables. Throughout the term of this Agreement and as Services are performed, Service Provider will deliver certain Licensed IP in the form of documentation, drawings, Confidential and Proprietary Information, intellectual property, software, applications, databases, procedures, and manuals. The categories of IP Deliverables are set forth in detail in Exhibit B (Deliverables), which identifies the IP and other deliverables to be provided by Service Provider under this Agreement. Service Provider will deliver such Licensed IP to Owners electronically to enable Owners' use of the IP Deliverables for Facility Purposes as set forth in this Agreement and in the IP License attached hereto as Exhibit G (IP License). Where available, Service Provider will deliver the "quality assurance record" (as that

term is defined in 10 CFR Part 50, Appendix B, XVII) of the Licensed IP, which is in .pdf format. When requested by Owners, Service Provider will also deliver the Licensed IP in .doc or .dwg format. Owners acknowledge that any Licensed IP delivered by Service Provider in .doc or .dwg format may contain errors and omissions, and are therefore being provided “as is, where is,” without warranty or any assurance of accuracy.

Nothing in this Section 6.1 shall restrict Owners’ right to receive or take possession of Facility IP pursuant to Exhibit F (Facility IP License in the Event of a Triggering Event). Except where provided in Exhibit F (Facility IP License in the Event of a Triggering Event), in no event will Service Provider be required to deliver to Owners the following categories of Licensed IP: (i) detailed design calculations and methodologies used to create Licensed IP; (ii) computer code input files and source codes; (iii) manufacturing technology and associated information; (iv) nuclear fuel design information; (v) safety analysis methodologies; and (vi) third party information which Service Provider does not have the contractual right to provide.

6.2 Maintenance of Facility IP. Except to the extent expressly precluded by law or court order, and then only to the narrowest extent required by such law or court order, Service Provider will maintain Facility IP, including any Facility IP newly developed during the term of this Agreement, in a form that enables Service Provider to perform the Services and preserves Owners’ right under Exhibits F (Facility IP License in the Event of a Triggering Event) and G (IP License).

6.3 Access to Facility IP. Regardless of whether certain Facility IP is deliverable under this Agreement, Westinghouse will provide Owners electronic access (except where electronic versions are unavailable or impractical for the required purpose) at the Site to the Facility IP, including but not limited to design calculations and all documents referenced or cited in the DCD and required to be incorporated into or referenced in the COL, as needed (i) to meet all applicable regulatory requirements and (ii) to exercise Owners’ oversight role (including participation in the design change process) (“Accessible IP”). The NRC will have the same access as Owners with respect to item (i) herein. Where Service Provider maintains electronic versions of Accessible IP, Service Provider will provide Owners’ personnel with access to read-only versions of such Accessible IP from workstations supplied by Service Provider for use on-Site and at Owners’ off-Site corporate offices. Owners’ access to Accessible IP will be available at any time, without the need for prior notice or authorization, with full implementation of this requirement to occur as soon as reasonably possible after the Effective Date. Owners will not copy or otherwise reproduce any Accessible IP. For Accessible IP that does not exist in electronic form, Service Provider will provide hard copies at the Site promptly upon Owners’ request.

6.4 Facility IP Licenses. Owners’ rights with respect to Facility IP shall be governed by the provisions of Exhibits G (IP License) and F (Facility IP License in the Event of a Triggering Event), which shall be executed in parallel to this Agreement and the terms of which are incorporated herein by reference. The sale or license of any Facility IP by Service Provider or its Affiliates shall not be free and clear of, or otherwise adversely effect, any license of Facility IP granted to Owners under the Agreement and Exhibits F (Facility IP License in the Event of a

Triggering Event) and G (IP License), pursuant to Section 363 of the Bankruptcy Code or other applicable law.

ARTICLE 7. CONTRACT RATES

The rates charged to Owners for the Services are set out in Exhibit C (Rates and Invoicing).

ARTICLE 8. INVOICES AND PAYMENTS

8.1 The requirements and processes applicable to invoices under this Agreement are set out in Exhibit C (Rates and Invoicing).

8.2 Respective Payment Responsibility. Owners shall be severally, not jointly, liable for the payments due hereunder; provided, however, that GPC shall act on behalf of all Owners for purposes of the receipt of invoices and aggregating the payments received from the Owners prior to making payment in accordance with the provisions of this Agreement. Each individual Owner is responsible for that percentage of payments due hereunder that is equivalent to such individual Owner's respective ownership interest percentage in the Project at the time such payment obligation accrues. In the event that an Owner does not pay in full the amount that is due from such Owner, and another Owner does not make such payment on behalf of such non-paying Owner, GPC shall notify Service Provider no later than the due date for the payment of the identity of the Owner(s) that did not pay in full and the amount of such shortfall in payment from such Owner(s).

ARTICLE 9. RECORDS; AUDIT

9.1 Subject to Service Provider's established records retention policy, Service Provider shall maintain and shall cause its subcontractors and vendors to maintain all technical documentation and other work product relative to the Services performed or provided under this Agreement throughout the term of this Agreement or for a longer period as required by applicable laws. If termination of this Agreement occurs prior to completion of the second Unit, Service Provider shall arrange for transfer of the lifetime quality records existing as of the date of the termination identified as Deliverables in Exhibit B (Deliverables) which Owners are required by NRC regulations or other applicable Law to retain as the NRC licensee for the Facility. The Service Provider may act as an authorized agent for retaining lifetime quality records in accordance with NQA-1-1994 as directed by Owners.

9.2 Except to the extent applicable laws require a longer retention, Service Provider shall maintain and shall cause its subcontractors and vendors performing services to maintain complete accounting records relating to the Services performed or provided and reimbursements from Owners due under this Agreement for a period of three (3) years after termination or completion of the Services, or such longer period as required by Law. Service Provider shall retain accounting records in accordance with generally accepted accounting principles in the United States, as set forth in pronouncements of the Financial Accounting Standards Board (and its predecessors) and the American Institute of Certified Public Accountants.

9.3 In addition to the obligations in Sections 9.1 and 9.2, Service Provider shall maintain its records in compliance with the applicable provisions of 10 C.F.R. § 50.71 and other applicable laws until such time as Service Provider delivers such records to Owners in accordance with this Agreement. At Owners' request, Service Provider shall allow Owners to audit and inspect its records related to the Services performed or provided under this Agreement in order for Owners to assess, verify, or demonstrate compliance with 10 C.F.R. § 50.71 and other applicable federal regulations.

9.4 At Owners' expense, Owners' third-party independent auditor will have the right not more than twice in a twelve month period to examine on Service Provider's premises all reasonable information required by Owners to substantiate proper invoicing. Such audit will provide Owners with a reasonable opportunity to verify that all costs and charges have been properly invoiced in accordance with the terms of this Agreement. In no event shall Owners have a right to demand an audit more than six months following the period to be audited. If an audit by the auditor reveals charges to or paid by Owners as charges or fees which are incorrectly charged, then Owners shall be entitled upon demand to a refund from Service Provider of such charges plus interest since the date of payment of the over-charges at a rate equal to the Prime Rate plus one percent (1%). The limitation of liability in Section 17.2 shall not impair Owners' entitlement to a refund under this Section 9.4. Notwithstanding anything in this Section 9.4 to the contrary, Owners shall not be restricted from any audit rights that they are required to have in order to comply with applicable laws, including without limitation the requirements of the NRC.

9.5 Service Provider shall provide, and shall use commercially reasonable efforts to require its subcontractors and vendors to provide, reasonable assistance to Owners in responding to requests and inspections by any Government Authority for information in connection with the Services.

ARTICLE 10. DEFECTIVE SERVICES AND EQUIPMENT WARRANTY

10.1 Professional Services . The Services under this Agreement which require a professional license under applicable law (e.g., engineering design work that must be performed by a licensed Professional Engineer) shall be performed (i) in a professional, prudent and workmanlike manner by qualified persons using competent, professional knowledge and judgment at the degree of skill and care customary to the nuclear power industry, and (ii) in accordance with Law, regulations, Licensing Basis, this Agreement, industry codes and standards. Subject to all limitations of Service Provider's liability in this Agreement, in the event that any Services which are subject to this Section 10.1, and which are not Secondment Services, result in work product that is determined to be defective, such work shall be re-performed by Service Provider at Service Provider's expense. Service Provider's total liability for any claims under this section shall be limited to the insurance proceeds recoverable from a mutually agreeable professional liability insurance policy covering Service Provider and the Services.

10.2 Non-Professional Services . Other labor Services provided under this Agreement which do not require a professional license under applicable law will be performed by qualified

personnel. For any such Services that are not Secondment Services that result in work product that is determined to be defective, Service Provider shall, at no cost to Owners, re-perform the Services.

10.3 Under this Agreement, work product shall only be deemed "defective" if it (i) contains clear and material errors in calculations, dimensions, configurations, specifications, or quantifications which cannot be dispositioned use-as-is; (ii) was created in a manner known to be contrary to written NRC regulations; or (iii) was created in a manner known to be contrary to the Licensing Basis. No work product shall be deemed defective if it is performed in accordance with the standard of care set forth in Section 10.1 or is a result of exercise of reasonable professional judgment. Re-performance of the Services shall be Owners' exclusive remedy and Service Provider shall not be responsible for any project costs or delays resulting therefrom.

10.4 Service Provider agrees that, in the event of a dispute with Owners regarding whether a failure to comply with the above requirements and obligations in Sections 10.1 or 10.2 occurred, Service Provider will continue with the Services and take all action necessary to correct, perform, or re-perform the Services in accordance with Owners' instructions to the extent allowed by law and reasonable professional judgment. Work performed under this section shall be invoiced and paid for in accordance with Exhibit C (Rates and Invoicing). No actions taken to remedy an alleged deficiency under this Section 10.4 shall prejudice Service Provider's right to assert a Claim.

10.5 Equipment Warranty.

(a) Third-Party Equipment. For any Facility equipment furnished through Service Provider, Service Provider shall (i) designate Owners as an express third-party beneficiary of such warranties, (ii) provide copies of all warranties and applicable contracts to Owners, and (iii) ensure that all available warranties are assigned to and operate for the benefit of Owners.

(b) Service-Provider Equipment. For any Facility equipment manufactured by Service Provider or its Affiliates and delivered after the Effective Date, Service Provider agrees to provide a commercially reasonable equipment warranty as is customary in the nuclear industry, subject to prior agreement by Owners to the terms of such warranty, which will be set forth in the procurement documents applicable to such equipment. This warranty shall be subject to the limitations of liability in Sections 17.1(a) and 17.2.

ARTICLE 11. REPRESENTATIONS AND WARRANTIES

11.1 Representations, Warranties and Covenants of Service Provider. Service Provider represents and warrants to Owners as follows:

(a) Organization and Power. Each entity constituting Service Provider is a corporation, limited liability company, or partnership duly organized, validly existing and in good standing under the laws of the state of its formation. Each Service Provider

entity is duly qualified as a foreign entity authorized to do business and is in good standing in every jurisdiction that such qualification is required, except where the failure to be so qualified would not have a material adverse effect on such entity.

(b) Authority; Binding Effect . As of the Effective Date, Service Provider has all requisite power and authority to execute and deliver this Agreement and all related documents, as applicable, and to provide the Services. As of the Effective Date, all necessary action by the board of directors and stockholders of WECTEC and the manager and/or the members of Westinghouse required to have been taken by or on behalf of each by applicable law, their respective formation documents or otherwise, have been taken to authorize (1) the execution and delivery on their behalf of this Agreement, and (2) the performance of their respective obligations hereunder. This Agreement will constitute as of the Effective Date the valid and binding agreement of Service Provider, enforceable against Service Provider in accordance with its terms, except (1) as the same may be limited by applicable bankruptcy, insolvency, moratorium or similar laws of general application relating to or affecting creditors' rights, including, without limitation, the effect of statutory or other laws regarding fraudulent conveyances and preferential transfers, and (2) for the limitations imposed by general principles of equity.

(c) No Conflict, Approvals . The execution and delivery of this Agreement does not and will not, and the performance of the Services will not: (1) violate or conflict with the charter documents of either of WECTEC or Westinghouse, (2) to the best of Service Provider's knowledge, conflict with or result in a violation of any permit, concession, franchise or license or any law, rule or regulation applicable to Service Provider or any of its properties or assets, except, in the case of clause (2), for any such breaches, conflicts or violations that would not reasonably be expected to have a material adverse effect on Service Provider and would not impair the ability of Service Provider to perform its obligations under this Agreement.

11.2 Representations and Warranties of Owners . Owners represent and warrant to Service Provider as follows:

(a) Organization and Power . Each Owner is a corporation duly organized, validly existing and in good standing under the laws of the state of its formation. Each Owner is duly qualified as a foreign entity authorized to do business and is in good standing in every jurisdiction that such qualification is required, except where the failure to be so qualified would not have a material adverse effect on such entity.

(b) Authority; Binding Effect . GPC has all requisite power and authority to execute and deliver this Agreement and all related documents, as applicable. All necessary action by the board of directors, stockholders, and/or manager of each Owner required to have been taken by or on behalf of such Owner by applicable law, its formation documents or otherwise, have been taken to authorize (1) the execution and delivery of this Agreement on its behalf and on behalf of such Owner, and (2) the performance of its obligations hereunder. This Agreement constitutes or will constitute

when delivered to Service Provider, as applicable, the valid and binding agreement of Owners, enforceable against each Owner in accordance with its terms, except (1) as the same may be limited by applicable bankruptcy, insolvency, moratorium or similar laws of general application relating to or affecting creditors' rights, including, without limitation, the effect of statutory or other laws regarding fraudulent conveyances and preferential transfers, and (2) for the limitations imposed by general principles of equity.

(c) No Conflict, Approvals . The execution and delivery of this Agreement does not and will not, and the performance of its obligations hereunder will not, (1) violate or conflict with the charter documents of Owners, or (2) subject to the consents specified in Section 3.2, constitute a breach or default (or an event that with notice or lapse of time or both would become a breach or default) or give rise to any lien, third party right of termination, cancellation, material modification or acceleration, or loss of any benefit, under any contract to which Owners is a party or by which it is bound, or (3) conflict with or result in a violation of any permit, concession, franchise or license or any law, rule or regulation applicable to Owners, except, in the case of clauses (2) and (3), for any such breaches, conflicts or violations that would not reasonably be expected to have a material adverse effect on Owners and would not impair the ability of Owners to perform its obligations under this Agreement.

(d) Governmental Approvals . Except as set forth in Section 3.2, neither the execution and delivery by GPC of this Agreement nor the performance by GPC and Owners of their obligations hereunder will require any Governmental Approval, except where the failure to obtain such Governmental Approval would not reasonably be expected to have a material adverse effect on Owners and would not impair the ability of Owners to perform their obligations under this Agreement.

ARTICLE 12. TITLE AND RISK OF LOSS

Title and risk of loss to all equipment that will become a permanent part of the Project or will be installed in the Project, and as provided under this Agreement, passes to Owners upon tender of such equipment to the carrier.

ARTICLE 13. QUALITY ASSURANCE REQUIREMENTS

13.1 (a) Service Provider currently has a quality assurance program(s), which will be used in the performance of Services under this Agreement and which has been accepted by the NRC ("Quality Assurance Program"). Service Provider will maintain its Quality Assurance Program and any changes thereto shall meet the requirements of 10 C.F.R. Part 50, Appendix B and ASME NQA-1 – 1994; provided however that compliance with ASME NQA-1 – 2008, including NQA-1a-2009 Addenda will be considered to be compliant with ASME NQA-1 – 1994. Any changes to Service Provider's Quality Assurance Program shall be submitted to and, if necessary, accepted by the NRC consistent with 10 C.F.R. 50.54(a) and accepted by Owners.

(b) Service Provider's Quality Assurance Program and associated policies and procedures shall address Service Provider's Services, including without limitation systems, structures and components in a manner consistent with their classification with respect to their importance to nuclear safety (i.e., safety related, important to safety, non-safety related) or their importance to the capacity, operability and reliability of the Facility as classified in the Vogtle Units 3 and 4 UFSAR.

(c) An interface document will be drafted and finalized prior to the conclusion of the Transition Period by the Service Provider and Owners to describe the interface between Service Provider and Owner Quality Assurance programs consistent with this Agreement.

(d) Service Provider's Quality Assurance Program is subject to review and audit by Owners for compliance with 10 C.F.R. Part 50, Appendix B and ASME NQA-1 - 1994. Owners' right to direct the quality assurance Services shall only extend to the Quality Assurance Program procedures and manuals applicable to the Project. Direction given by Owners shall be Project-specific and shall not require Service Provider to modify its Quality Assurance Program in such a way that the modification would impact other projects or Service Provider activities not being undertaken in support of the Project.

13.2 (a) Service Provider shall be responsible to perform the quality control and inspection Services to the extent specified by Owners as determined in the Transition Period. The quality control and inspection activities will be consistent with the nuclear safety quality classification of the system, structure or component under evaluation. The Persons performing quality control functions for Service Provider shall report organizationally such that inspection activities are performed consistent with 10 C.F.R. Part 50, Appendix B and NQA-1-1994.

(b) Nothing in this Section 13.2 shall prevent Owners from performing any quality control and inspection activities themselves or designating a Third Party to so perform, in accordance with Section 4.3(b) governing the reduction or elimination of certain Services or portions thereof. In the event that Owners provide notice that any quality control and inspection activities will be transitioned to Owners or to a Third Party, Owners will specify the Services necessary from Service Provider to support such transition; provided that inspection activities during and after such transition will continue to remain consistent with ASME NQA-1 and 10 C.F.R. Part 50, Appendix B requirements. Owners will compensate Service Provider in accordance with Exhibit C (Rates and Invoicing) for such Services, and Service Provider will perform the specified Services in support of such transition.

13.3 (a) For purposes of the ASME Code, Service Provider shall be designated as Owners' agent as referenced in the Nuclear Development ASME Quality Assurance Manual ("NDAQAM"). Westinghouse and WECTEC have provided Owners with the documentation regarding their existing ASME QA programs and ASME N-stamp certificates as referenced in NDAQAM, in accordance with ASME requirements. Westinghouse and WECTEC agree that they will maintain those programs and certificates as they exist as of the Execution Date of this Agreement and will not take any action that will alter their ASME status for purposes of the

Services covered by this Agreement for the Project. Westinghouse and WECTEC may update their ASME QA programs and certificates as required to maintain compliance with the ASME Code in accordance with 10 C.F.R. §50.54(a).

(b) Work performed at Vogtle Units 3 and 4, in accordance with this Agreement, which is subject to ASME Code shall be performed in accordance with Owners, Westinghouse and WECTEC ASME QA programs to meet the requirements of ASME Certificate Holder responsibilities. For the performance of ASME Code responsibilities, a specific ASME interface agreement will be maintained between the Parties.

(c) The Parties recognize that ASME QA programs and ASME N-stamp certificates involve significant time and effort to obtain, are important to the Project, and that it would cause immediate, significant impacts to Owners should Service Provider cease to maintain its ASME status or cease performing the Services governed by ASME QA and N-stamp requirements. In recognition of the unique nature of ASME QA programs and N-stamp certificate requirements, Service Provider agrees to provide Owners with notice, in writing, six (6) months before taking any action that would impact its ASME status or ceasing to perform the Services governed by the ASME QA and N-stamp requirements. If Service Provider has provided such notice and Owners request support, then the Service Provider agrees to provide the applicable Services as necessary to support the transition of ASME QA and N-stamp requirements to Owners or its Representative as directed by Owners.

13.4 Some of the Services performed under this Agreement may be subject to the provisions of 10 C.F.R. Part 21 and 10 C.F.R. § 50.55(e). A copy of Service Provider notifications relative to this Agreement to the NRC pursuant to 10 C.F.R. Part 21 or 10 C.F.R. § 50.55(e), if any, shall be transmitted to Owners. Service Provider will notify Owners of nonconformances reportable to the NRC as well as nonconformances judged not reportable to the NRC but which are considered to be a "Significant Condition Adverse to Quality" pursuant to ASME NQA-1 – 1994 and are relevant to the AP1000 ® and the Project.

13.5 (a) The Service Provider qualifies safety-related suppliers in accordance with the requirements in 10 C.F.R. Part 50, Appendix B and ASME NQA-1 – 1994 and maintains a list of these qualified suppliers. The Service Provider shall continue to maintain the qualification of the suppliers performing Services governed by this Agreement that are currently on Service Provider's list of qualified suppliers. Suppliers who are no longer performing Services related to the Project may be removed from the list with Owners' concurrence. Service Provider will provide (i) access pursuant to Section 13.6 for the qualified suppliers involved in the Services performed under this Agreement, and (ii) information described in Section 13.5(d) supporting Service Provider's qualified suppliers list that Owners request in order to procure materials, components and/or services for the Project.

(b) For those suppliers governed by Section 13.5 of this Agreement, the Service Provider will establish a method to communicate to Owners on an on-going basis current supplier status, for Project procurement activities, whether such procurement is performed by Owners, a Third Party, or Service Provider.

(c) Owners may request Service Provider to provide auditing, evaluation or source verification Services for new or current suppliers for the Project, and Service Provider will provide such auditing or evaluation Services regardless of whether the new suppliers will be included on Service Provider's list of qualified suppliers or on Owners' list of qualified suppliers. These auditing, evaluation, or source verification Services will be completed at a mutually agreed upon time among Owners, the Service Provider and the supplier.

(d) Service Provider shall perform all annual evaluations and audits that are part of the Services provided pursuant to this Section 13 in compliance with applicable Law. Service Provider shall not use a grace period pertaining to the same without Owners' prior written approval which shall not be unreasonably withheld. Service Provider shall provide the quality records as required by the Owners' quality assurance program to utilize these suppliers. Audit reports produced under agreement by Third Party sources (example NIAC) are prohibited by agreement to be provided to Owners. For such audit reports only, Owners may receive the outcome, i.e. qualification status, or may review the associated quality records at the Service Provider's facilities pursuant to Section 13.6.

13.6 Owners' Representative(s) shall be given reasonable access to Service Provider's facilities and records for inspection and audit of the Quality Assurance Programs. Service Provider shall use commercially reasonable efforts to ensure that all future procurement purchase orders and contracts prepared by Service Provider include provisions for access by Owners or their Representative(s) to Service Provider's and vendors' facilities and records for similar inspection and audit.

ARTICLE 14. CONFIDENTIAL AND PROPRIETARY INFORMATION

14.1 As used in this Agreement, "Confidential and Proprietary Information" means the terms of this Agreement and any and all information, data, software, matter or thing of a secret, confidential or private nature identified as "confidential", "proprietary" or the like by the Party which claims the information to be proprietary, relating to the business of the disclosing Party or its Affiliates, including matters of a technical nature (such as know-how, processes, data and techniques), matters of a business nature (such as information about schedules, costs, profits, markets, sales, customers, suppliers, the Parties' contractual dealings with each other and the projects that are the subject-matter thereof), matters of a proprietary nature (such as information about patents, patent applications, copyrights, trade secrets and trademarks), other information of a similar nature, and any other information which has been derived from the foregoing information by the receiving Party; provided, however, that Confidential and Proprietary Information shall not include information which: (a) is legally in possession of a receiving Party prior to receipt thereof from the other Party; (b) a receiving Party can show by reasonable evidence to have been independently developed by the receiving Party or its employees, consultants, Affiliates or agents; (c) enters the public domain through no fault of a receiving Party or others within its control; or (d) is disclosed to a receiving Party by a third party, without restriction or breach of an obligation of confidentiality to the disclosing Party.

14.2 Notwithstanding any prior agreements between the Parties governing the protection of Service Provider's or Owners' Confidential and Proprietary Information transferred or used in connection with the Project, including provisions in such prior agreements regarding the survival of the Parties' confidentiality obligations in connection therewith, as of the Effective Date, the provisions of this Article 14 shall control the protection of all Confidential and Proprietary Information transmitted or used in connection with the Project regardless of whether such information was covered by a previous agreement between the Parties.

14.3 Use and Protection of Owners' Confidential and Proprietary Information .

(a) Title to Confidential and Proprietary Information provided by Owners to Service Provider and all copies made by or for Service Provider in whole or in part from such Confidential and Proprietary Information remains with Owners. Service Provider agrees that it will not, during or for fifteen (15) years after the term of this Agreement, disclose any Confidential and Proprietary Information of Owners and their Affiliates, which is provided to Service Provider during the performance of Services under this Agreement to any Person (other than subcontractors or vendors, as required for the performance of the Services, provided that such subcontractors or vendors agree in writing to be bound by the same obligation of non-disclosure and confidentiality as provided in this Section 14.3), or to the general public for any reason or purpose whatsoever without the prior written consent of Owners, and that such Confidential and Proprietary Information received by Service Provider shall be used by it exclusively in connection with the performance of its responsibilities relating to the Services to be performed hereunder. Notwithstanding the foregoing, the above fifteen (15) year period shall not apply to Confidential and Proprietary Information of Owners which is defined by Law as Owners' trade secrets, which Confidential and Proprietary Information shall be maintained as confidential and proprietary by Service Provider as permitted under applicable Law. Nothing herein grants the right to Service Provider (or implies a license under any patent) to sell, license, lease, or cause to have sold any Confidential and Proprietary Information supplied by Owners under this Agreement. However, nothing herein shall prevent Service Provider from disclosing Confidential and Proprietary Information of Owners or their Affiliates as required by Law or an order of a Government Authority; provided that Service Provider shall, if Service Provider has adequate advance notice, give Owners reasonable notice so as to allow Owners to seek a protective order or similar protection. If, in the opinion of its legal counsel and in the absence of a protective order or waiver, Service Provider is legally compelled to disclose Owners' Confidential and Proprietary Information, Service Provider will disclose only the minimum amount of such information or data as, in the opinion of its legal counsel, is legally required. In any such event, Service Provider agrees to use good faith efforts to ensure that the Confidential and Proprietary Information that is so disclosed will be accorded confidential treatment. In addition, Service Provider may, upon Owners' written permission, which shall not be unreasonably withheld, and in accordance with the below, be authorized to receive and use certain Confidential and Proprietary Information of Owners for the limited use and purposes of performing or assisting in the performance of

start-up, commissioning, licensing and start-up maintenance services for other AP1000 ® nuclear power plant owners. Any such request by Service Provider shall identify (i) the specifics of the Owners' Confidential and Proprietary Information to be used, (ii) the specific use and purposes for which it is intended to be applied by Service Provider, including an explanation of why Service Provider requires Owner's Confidential and Proprietary Information, (iii) whether Service Provider intends to disclose such information to Third Parties, and if so, the identity of such Third Parties, and (iv) Service Provider's assurances that it will exercise reasonable efforts consistent with its efforts to protect against the unauthorized disclosure of its own Confidential and Proprietary Information, to preclude against the unauthorized disclosure or publication of Owner's Confidential and Proprietary Information. Service Provider shall obtain written assurances from any Third Party recipients that they will not use, disclose or publish Owners' Confidential and Proprietary Information except as expressly authorized by Owners for the limited use and purposes identified by Service Provider as required in (ii) above.

(b) In the use of any Confidential and Proprietary Information of the other Party for the purpose of providing required information to, and/or securing Governmental Approvals from, any Government Authority, Owners and Service Provider will cooperate to minimize the amount of such information furnished consistent with the interests of the other Party and the requirements of the Government Authority involved.

(c) Nothing herein shall prevent Service Provider from disclosing to the appropriate Government Authority any noncompliance or violation of Laws within the jurisdiction of such Government Authority.

(d) Should Service Provider discover a breach of the terms and conditions of a non-disclosure and confidentiality agreement with a Third Party to which it is permitted to disclose Owners' Confidential and Proprietary Information under this Agreement, Service Provider will promptly notify Owners of such breach and provide to Owners necessary information and support pertaining to any suit or proceeding brought by Owners against Recipient for such breach.

(e) Owners shall not be responsible to Service Provider or Third Parties for the consequence of the use or misuse of Owners' Confidential and Proprietary Information by Service Provider or Third Parties, and Owners make no warranties, express or implied, to the extent of any use or misuse of Owners' Confidential and Proprietary Information by Service Provider or Third Parties.

14.4 Protection of Service Provider's Confidential and Proprietary Information

(a) Owners' Use .

(i) Owners agree to use Confidential and Proprietary Information provided by Service Provider and copies thereof, including Licensed IP and

Deliverables, solely for the purposes of Facility (and associated simulators) construction, testing, completion of ITAACs, start-up, trouble-shooting, response to plant events, inspection, evaluation of system or component performance, scheduling, investigations, operation, maintenance, training, repair, licensing, modification, decommissioning and compliance with Laws or Government Authorities (collectively, the "Facility Purposes"). Nothing herein grants the right to Owners (or implies a license under any patent) to sell, license, lease, or cause to have sold any Confidential and Proprietary Information supplied by Service Provider under this Agreement.

(ii) Title to Confidential and Proprietary Information provided by Service Provider to Owners and all copies made by or for Owners in whole or in part from such Confidential and Proprietary Information remains with Service Provider. Owners shall include Service Provider's confidential or proprietary markings as provided by Service Provider on all copies thereof and excerpts made therefrom except with respect to excerpts made or used internally by Owners for Facility Purposes; provided, however, that Owners shall destroy any such excerpts which do not include Service Provider's confidential or proprietary markings when no longer needed for the purpose for which they were made. Except as otherwise provided under this Section 14.4 or Section 14.5, Owners agree to keep such Confidential and Proprietary Information confidential, to use such Confidential and Proprietary Information only for the Facility Purposes and not to sell, transfer, sublicense, disclose or otherwise make available any of such Confidential and Proprietary Information to others (other than Affiliates and Representatives). However, nothing in this Article 14 shall prevent Owners from disclosing Confidential and Proprietary Information of Service Provider or its Affiliates as required by Law or an order of a Government Authority (including without limitation the COL and/or Georgia PSC Certification Order); provided that Owners shall, if Owners have adequate advance notice, give Service Provider reasonable notice so as to allow Service Provider to seek a protective order or similar protection. If, in the opinion of Owners' legal counsel and in the absence of a protective order or waiver, Owners are legally compelled to disclose Confidential and Proprietary Information, Owners will disclose only the minimum amount of such information or data as, in the opinion of Owners' legal counsel, is legally required. In any such event, Owners agree to use good faith efforts to ensure that Confidential and Proprietary Information that is so disclosed will be accorded confidential treatment.

(iii) Service Provider hereby grants to Owners and their Affiliates, officers, directors, employees, attorneys and Representatives who have a need for access to know such Confidential and Proprietary Information reasonably related to the exercise of any rights of the Owners hereunder a transferable (but only as part of the sale or transfer of the Facility or the operating responsibilities related thereto), royalty-free, fully paid up, irrevocable, nonexclusive, perpetual license to

use and copy Service Provider's Confidential and Proprietary Information but only for the Facility Purposes (and for the associated simulators).

(b) Owners' Disclosure to Third Party Recipients .

(i) The disclosure by Owners to Third Parties (hereinafter referred to as "Recipients" or "Recipient") of Service Provider's Confidential and Proprietary Information that has been furnished to Owners prior to or after the Effective Date of this Agreement, shall be governed exclusively by the provisions of this Agreement, and shall be made in accordance with the procedures and subject to the limitations set forth in Sections 14.4 and 14.5.

(ii) Owners shall enter into a Confidentiality Agreement with the Recipient substantially on the terms set forth in Exhibit E (Form of Confidentiality Agreement); provided, however, that the Owners may disclose such Confidential and Proprietary Information without entering into such agreements to those persons to which access is required by any Government Authority or as necessary in order to comply with Law, or, in the case of Owners that receive financing from or are subject to the rules or regulations of the U.S. Rural Utilities Service and the U.S. Department of Energy, such Owners may disclose such Confidential and Proprietary Information without entering into such agreements to the U.S. Rural Utilities Service and the U.S. Department of Energy. Any Recipient that has executed a confidentiality agreement or acknowledgement in a form attached to the EPC Agreement or agreement otherwise agreed to by Service Provider in connection with the provision of Confidential and Proprietary Information associated with the Project shall not be required to execute a new confidentiality agreement in the form of Exhibit E (Form of Confidentiality Agreement), it being agreed by the Parties that the confidentiality agreement or acknowledgment signed by such Recipient shall remain in effect for the purposes of and shall satisfy the requirements of, and be considered a Confidentiality Agreement under, this Article 14.

(iii) Should Owners discover a breach of the terms and conditions of a Confidentiality Agreement with a Third Party, Owners will promptly notify Service Provider of such breach and provide to Service Provider necessary information and support pertaining to any suit or proceeding contemplated or brought by Service Provider against Recipient for such breach.

(iv) Service Provider shall not be responsible to Owners for the consequence of the use or misuse of Service Provider's Confidential and Proprietary Information by Third Parties. Service Provider makes no warranties, express or implied, to the extent of any such use or misuse of Service Provider's Confidential and Proprietary Information by Third Parties.

(v) Nothing herein shall prevent Owners from disclosing to the appropriate Government Authority any noncompliance or violation of Laws within the jurisdiction of such Government Authority.

(c) Export Control .

(i) Each Party agrees not to disclose, directly or indirectly transfer, export, or re-export any Confidential and Proprietary Information, or any direct or indirect products or technical data resulting therefrom to any country, natural person or entity, except in accordance with applicable export control Law.

(ii) To assure compliance with the export control Laws and regulations of the United States government, specifically the U. S. Department of Energy export regulations of nuclear technology under 10 C.F.R. Part 810, the U.S. Nuclear Regulatory Commission export and import regulations related to nuclear equipment and material under 10 C.F.R. Part 110, and the U.S. Department of Commerce export regulations of commercial or dual-use technology under 15 C.F.R. Part 730 et seq. concerning the export of technical data or similar information to specific countries, locations, or entities, a Party shall not disclose or permit the disclosure, transfer or re-export, directly or indirectly, of any Confidential and Proprietary Information it receives hereunder that a receiving Party considers to be potentially subject to U.S. export control, or any product or technical data derived from such Confidential and Proprietary Information, except in compliance with such export control laws and regulations, which may be contingent on additional United States Governmental Approvals.

(iii) Each Party shall cooperate in good faith with the reasonable requests of the other Party made for purposes of either Party's compliance with such Laws and regulations. Service Provider acknowledges that Confidential and Proprietary Information which is subject to U.S. export control is contained within databases and/or servers located at the Site. Service Provider shall ensure that all Service Provider personnel granted access to the Site shall (a) not be included in any published lists maintained by the U.S. government of persons and entities whose export or import privileges have been denied or restricted and (b) either be a U.S. Person (defined as a U.S. citizen, lawful permanent resident, or protected individual under the Immigration and Naturalization Act of 8 U.S.C. § 1324b(a)(3)), person from a "generally authorized" country, the recipient of a "deemed export" authorization, or a person acting under continuance activities per the savings clause provision of 10 C.F.R. § 810.16(b), and Service Provider shall be required to maintain with Owner or obtain such authorizations as needed and comply with any and all corresponding reporting obligations. Nothing in this Section 14.4(c)(iii) shall limit Owners' right to deny access to the Site to any Service Provider personnel where Owners determine that granting access would not comply with applicable Law. In the event the Parties agree that a formal

technology control plan or an additional server or database is needed to maintain appropriate management of Confidential and Proprietary Information subject to export control, the Parties shall cooperate to agree and implement such additional measures.

(iv) Notwithstanding any other provisions in this Agreement, the obligations set forth in this Section 14.4(c) shall be binding on the Parties so long as the relevant United States export control Laws and regulations are in effect.

14.5 Special Procedures Pertaining to Service Provider's Confidential and Proprietary Information.

(a) Categories of Service Provider Information. The Parties acknowledge and agree that certain Confidential and Proprietary Information of Service Provider delivered to Owners under this Agreement in accordance with Exhibit B (Deliverables) as Licensed IP may be disclosed on a confidential basis without the prior consent of Service Provider ("Service Provider Disclosable Information," as described in Section 14.5(b)), and that certain other Confidential and Proprietary Information of Service Provider delivered to Owners as Licensed IP may not be disclosed by Owners to any Third Parties without the prior consent of Service Provider ("Service Provider Non-Disclosable Information," as described in Section 14.5(d)). Owners agree to abide by the provisions of this Section 14.5 governing the release of Service Provider's Confidential and Proprietary Information.

(b) Service Provider Disclosable Information. Service Provider Disclosable Information consists of the following Confidential and Proprietary Information that has been developed by Service Provider, to the extent such information does not include Service Provider Non-Disclosable Information as described in Section 14.5(d), below:

(i) Descriptions of the plant, its components, or its systems (physical characteristics, general outline drawings, equipment lists, termination drawings, general arrangement drawings, electrical drawings, and basic schematic drawings);

(ii) Plant, component, or system data that can be measured by plant sensors;

(iii) Information that may be acquired by physical measurement, such as location, dimensions, weight and material properties;

(iv) Service Provider operating and maintenance manuals, and QA documentation;

(v) Erection and commissioning documentation such as installation and layout drawings, and control room panel assembly and location drawings;

(vi) Information or calculations directly developed using publicly available methods or data;

(vii) Final results of calculated information or input assumptions to calculated information such that calculations could be recreated by a Third Party using the Third Party's own then-existing methods (excluding Service Provider-developed test or experience-based data, methodologies, correlations and models, which Service Provider will not release to the Owners);

(viii) Design specifications for non-safety related equipment and system specification documents ("SSDs") for non-safety related systems with the exception of the following: (A) all design specifications for non-safety Instrumentation & Control ("I&C") systems, and (B) SSDs identified for the systems listed below:

(1) Chemical and Volume Control System

(2) Data Display and Processing System

(3) Diverse Actuation System

(4) Incore Instrumentation System

(5) Operation and Control Centers

(6) Plant Control System

(7) Main Turbine Control and Diagnostics System

(8) Main Generation System

(9) Special Monitoring Systems; and

(ix) Documents, materials, and underlying data created and provided under Section 5.5.

(c) Procedures for Release of Service Provider Disclosable Information. Service Provider Disclosable Information may be disclosed by Owners to Third Parties without prior notice to Service Provider, provided that such disclosure is exclusively for the Facility Purposes and provided that:

(i) Owners shall take reasonable steps to minimize the disclosure of Service Provider's Confidential and Proprietary Information to only that information necessary for a Recipient to perform its contracted functions;

(ii) Owners shall execute a Confidentiality Agreement substantially in the form of Exhibit E (Form of Confidentiality Agreement) with the Recipient governing the disclosure of Service Provider's Confidential and Proprietary Information consistent with Section 14.4(b)(ii);

(iii) Service Provider has the right to audit Owners' records and the contents of any agreements (subject to Owners right to protect confidential and proprietary information of Owners and Third Parties) executed between Owners and a Recipient governing the disclosure of Service Provider's Confidential and Proprietary Information; and

(iv) The provisions of Section 14.4(b)(iii), (iv) and (v) shall apply to such disclosure.

(d) Service Provider Non-Disclosable Information. Service Provider Non-Disclosable Information consists of the following information that has been developed by Service Provider:

(i) Calculation for safety-related equipment and systems;

(ii) Plant Design Model;

(iii) I&C functional system software and interface requirements and functional logic diagrams;

(iv) Design specifications and qualification reports for safety-related equipment;

(v) SSDs for safety related systems;

(vi) I&C architecture diagrams, I&C software verification and validation documentation, I&C testing procedures and test results;

(vii) Component data packages which include Manufacturing Deviation Notices, Certified Material Test Reports and Quality Releases (will typically be provided to the Owners in the final data package if the deviations exceed the official design/fabrication specifications); and

(viii) Information which contains confidential intellectual property of Service Provider's subcontractors, vendors, or other Service Provider utility customers which is licensed to Service Provider and which Service Provider has the right to sub-license to Owners, or confidential intellectual property of Service Provider's subcontractors or vendors licensed directly to Owners.

(e) Procedures Pertaining to Service Provider Non-Disclosable Information . Upon written request by Owners in accordance with the provisions of this Section 14.5(e), Service Provider shall consider the disclosure of Service Provider Non-Disclosable Information. The request shall identify the information requested to be disclosed, the work that is to be performed and the name of the intended Recipient. The request shall be in writing sent to Service Provider. The request shall be reviewed by Service Provider for acceptability for disclosure based on the principle, agreed to by Owners and Service Provider, that Service Provider has the right to protect its proprietary information in which it has made a substantial investment and which required substantial innovation, balanced against whether such disclosure would jeopardize such proprietary rights of Service Provider and the principle that Owners have the right to assure that services associated with maintenance and operation of the Facility are in all respects prudent, including cost, and thus may need to be performed by Third Party service providers. The determination of whether or not to disclose the information shall be made by Service Provider in its discretion based on the above principles and with an agreement that information can be adequately protected by requiring Third Party employees to work solely for the Project and to segregate information from the Third Party's corporate servers and other Third Party employees. Service Provider shall make commercially reasonable efforts to respond within five (5) business days of receipt of a written request from Owners to disclose specific Service Provider Non-Disclosable Information. If, at the end of fifteen (15) business days following such receipt by Service Provider of a written request from Owners to disclose specific Service Provider Non-Disclosable Information, Service Provider has not rejected the request to disclose specific Service Provider Non-Disclosable information, such request shall be deemed accepted by Service Provider. If Service Provider agrees to the disclosure of such information, the specific information to be provided to the Recipient (subject to Owners' right to protect Confidential and Proprietary Information of Owners and Recipient) shall be subject to review and approval by Service Provider and shall be governed by the terms of the confidentiality agreement with the Recipient substantially in the forms set forth in Exhibit E (Form of Confidentiality Agreement).

(f) Documents Containing Combined Information . Where a document marked "Confidential and Proprietary" or the like contains Service Provider Disclosable Information and Service Provider Non-Disclosable Information, Owners shall not disclose any Service Provider Non-Disclosable Information without Service Provider's prior written consent. Owners shall have the right to:

(i) request Service Provider to prepare and verify the accuracy of a version of such document containing only Service Provider Disclosable Information;

(ii) request Service Provider to prepare and verify the accuracy of a document which contains the specific information requested by the Third Party service provider; or

(iii) itself extract the Service Provider Disclosable Information from such document and provide the Disclosable Information to the Third Party service provider in accordance with the procedures set forth in Section 14.5(c). All right, title and interest in Service Provider Disclosable Information contained in such document or material prepared by Owners remains with Service Provider and, for the avoidance of doubt, is hereby assigned to Service Provider. Owner shall make commercially reasonable efforts to give notice to Service Provider and access prior to disclosure of any extract of Service Provider Disclosable Information and will provide a copy of such upon Service Provider's request.

Service Provider shall be reimbursed pursuant to Exhibit C (Rates and Invoicing) for the preparation and verification of documents for Owners under Section 14.5(f)(i) and (ii) above. Service Provider shall assume no liability for, and will not warrant the accuracy or validity of, any version of a document containing Service Provider Disclosable Information prepared by Owners pursuant to Section 14.5(f)(iii) above.

(g) Additional Procedures. Owners and Service Provider shall each designate a contact person for the purposes of administering the release of Service Provider's Confidential and Proprietary Information. Owners' contact person shall be responsible for (i) ensuring that an agreement is executed with the Recipient governing the disclosure of Service Provider Confidential and Proprietary Information consistent with Section 14.4(b) before the information is released and (ii) making formal requests to Service Provider for the release of information designated as Service Provider's Non-Disclosable Information. Service Provider's contact person shall be responsible for (i) handling and expediting responses to Owners' requests for release of information not specifically designated as Service Provider Disclosable Information and (ii) conducting periodic reviews of Owners' records listing the Recipients and purposes of disclosure of Service Provider Confidential and Proprietary Information.

14.6 Software. Software provided to Owners by Service Provider shall be subject to the license provisions set forth in Exhibit G (IP License).

14.7 Nothing in this Article 14 limits Owners' rights pursuant to Article 6 or the Exhibit F (Facility IP License in the Event of a Triggering Event); provided that Owners will comply with the provisions of Article 6 or the Facility IP License in the Event of a Triggering Event, as applicable, with respect to the sharing of Confidential and Proprietary Information with

any third party. Each Party acknowledges that, during the term of this Agreement, it may have access to Confidential and Proprietary Information of the other Party and its Affiliates, including Third Party proprietary information, which represents a substantial investment. Unless the disclosing Party agrees otherwise in advance and in writing, or unless provided otherwise in this Agreement, the receiving Party agrees that it will limit access to such Confidential and Proprietary Information, including Third Party proprietary information, to its directors, officers, employees, and Representatives, who require the information in connection with activities under this Agreement.

(a) Each receiving Party agrees to exercise reasonable efforts, consistent with or better than the efforts that it exercises to protect information of its own that it regards as confidential or proprietary, to keep such Confidential and Proprietary Information in confidence and not to copy or permit others to copy or access the information or disclose, redistribute, or publish the same to unauthorized persons.

(b) Each receiving Party agrees that, except where Service Provider elects to do so in order to utilize service support located outside the United States, disclosing Party's Confidential and Proprietary Information will exclusively be stored, processed, accessed and/or viewed in or from United States data centers and receiving Party will not export any such Confidential and Proprietary Information nor allow access by any foreign national contrary to the laws of the United States. The release of any Confidential and Proprietary Information to receiving Party will be subject to and in accordance with any applicable laws, including applicable United States export laws and regulations (if any).

(c) Each receiving Party acknowledges and agrees that any disclosure or use of the disclosing Party's Confidential and Proprietary Information, except as otherwise authorized herein or by disclosing Party in writing, would be wrongful and cause immediate and irreparable injury to disclosing Party or to any third party owner whose Confidential and Proprietary Information is under disclosing Party's care and custody and agrees to cooperate with disclosing Party in obtaining an injunction if necessary to prevent further disclosure thereof.

(d) Each receiving Party agrees to immediately notify disclosing Party of any unauthorized disclosure or use or any such Confidential and Proprietary Information of which receiving Party becomes aware, and receiving Party will be liable to disclosing Party for any such unauthorized disclosure or use of such Confidential and Proprietary Information.

14.8 Special Recipients.

(a) The Parties acknowledge that Owners and the owners and operators of the V.C. Summer project ("VCS Owners") may be working closely together on their respective AP1000® projects. Owners and VCS Owners may coordinate with, undertake joint work initiatives with, share information with, or make similar arrangements whereby Owners and the VCS Owners are seeking alignment, cost sharing, efficiency, or

otherwise combining their efforts. Owners and the VCS Owners will have the right to discuss and share Confidential and Proprietary Information for purposes of discussing the Vogtle or V.C. Summer projects. For purposes of this Article 14, the VCS Owners will not be considered third parties but will be treated in the same manner as Owners' employees.

(b) For credit rating agencies (e.g., S&P, Moody's) and any financial institution, bank, or Government Authority that is a lender or guarantor for any Owner(s), Owners shall have the right to disclose certain non-technical Confidential and Proprietary Information of Service Provider without requiring the Recipient to execute a non-disclosure agreement. The non-technical Confidential and Proprietary Information referred to in this section includes, by way of illustration and not limitation, this Agreement, status reports relating to the Project schedule and estimated Project costs, paid-to-date information, cost estimates, and agreements with respect to the assignment or potential assignment of this Agreement; provided, however, that Owners have reasonable assurance from the agency, institution, bank, or entity that the Confidential and Proprietary Information will receive confidential treatment.

ARTICLE 15. CONTRACT ADMINISTRATION NOTICES

All notices specifically related to the terms and conditions of this Agreement or otherwise required under this Agreement shall be effective only at the time of receipt thereof and only when received by the Parties to whom they are addressed at the following addresses:

If to Owners :

Georgia Power Company
Attn: David L. McKinney, Vice President-Nuclear Development
241 Ralph McGill Blvd., NE
BIN 102321
Atlanta, GA 30308
Email: dlmckinn@southernco.com

Southern Nuclear Operating Company, Inc.
Attn: Mark D. Rauckhorst
Executive Vice President-Vogtle 3/4 Construction
7825 River Road
BIN 63031
Waynesboro, GA 30830
Email: mdrauckh@southernco.com

Balch & Bingham LLP
Attn: M. Stanford Blanton
1710 Sixth Avenue North
Birmingham, AL 35203
Email: sblanton@balch.com

If to Service Provider :

Westinghouse Electric Company LLC
Attn: Michael T. Sweeney, Senior Vice President
& General Counsel
1000 Westinghouse Drive
Cranberry Township, PA 16066
Email: sweenemt@westinghouse.com

WECTEC Global Project Services Inc.; Westinghouse Electric Company LLC
Attn: David Durham, President WECTEC; Senior Vice President New Project Business
3735 Glen Lake Drive
Charlotte, NC 28208
Email: durhamdc@westinghouse.com

ARTICLE 16. INDEMNITY

16.1 Service Provider Indemnity . Except with respect to a Nuclear Incident, as that term is defined under the Atomic Energy Act of 1954, as amended (the "AEA"), Service Provider shall indemnify, hold harmless and defend Owners, their present and future Affiliates and the respective directors, officers, employees, representatives, agents, shareholders, attorneys, successors and assigns of each of them and all persons or entities claiming through them (collectively referred to as "Owner Persons Indemnified"), from and against (i) all third party claims associated with any injury of or death to natural persons or damage to or destruction of third party property to the extent that such injury, death or damage is proximately caused by or arises out of the negligence or willful misconduct of Service Provider in the performance or prosecution by Service Provider or its Representatives of the Services hereunder; (ii) any violation of Law to the extent such violation of Law is made by Service Provider, its subcontractors, or the Representatives of either acting within the scope of their employment; (iii) any and all claims, demands, causes of action, damages, liabilities, losses, penalties, costs and expenses (including reasonable attorneys' fees) associated with (A) the release on or from the Site or any other location of any Hazardous Materials to the extent caused by the negligent acts or negligent omissions or willful misconduct of Service Provider, its subcontractors, or their Representatives acting within the scope of their employment, or (B) contamination of the environment or injury to natural resources resulting from Hazardous Materials to the extent caused by the negligent acts or omissions or willful misconduct of Service Provider, its subcontractors, or their Representatives acting within the scope of their employment; and (iv) any and all claims, losses, damages, liabilities, legal fees and expenses resulting from or arising in connection with any failure of Service Provider, its subcontractors, or their Representatives to pay salaries or wages, payroll taxes and employee benefits, or to withhold appropriate taxes. The Parties agree that the indemnity obligations of this section do not apply to any claims, demands,

causes of action, damages, liabilities, losses, penalties, costs and expenses caused by acts or omissions of Service Provider employees seconded to Owners.

16.2 Owners' Indemnity . Owners shall indemnify, hold harmless and defend Service Provider, its present and future Affiliates and the respective directors, officers, employees, representatives, agents, shareholders, attorneys, successors and assigns of each of them and all persons or entities claiming through them (collectively referred to as "Service Provider Persons Indemnified"), from and against (i) all third party claims associated with any injury of or death to natural persons or damage to or destruction of third party property to the extent that such injury, death or damage is proximately caused by or arises out of the negligence or willful misconduct of Owners or their Representatives in the performance or prosecution by Owners or its Representatives of work related to the Project; (ii) any violation of Law to the extent such violation of Law is made by Owners or their Representatives in the performance or prosecution by Owners or their Representatives of work related to the Project; (iii) any and all claims, demands, causes of action, damages, liabilities, losses, penalties, costs and expenses (including reasonable attorneys' fees) associated with (A) the Release on or from the Site or any other location of any Hazardous Materials to the extent caused by the negligent acts or negligent omissions or willful misconduct of Owners or their Representatives in the performance or prosecution by Owners or their Representatives of work related to the Project, or (B) contamination of the environment or injury to natural resources resulting from Hazardous Materials to the extent caused by the negligent acts or omissions or willful misconduct of Owners or their Representatives in the performance or prosecution by Owners or their Representatives of work related to the Project; (iv) all third-party claims of delay, additional work, or other commercial claims, in all such cases arising after the Effective Date, by any third-party contractor having privity with Owners and performing work related to the Project, or by such contractor's subcontractors, vendors or suppliers, performing work related to the Project; and (v) all third-party claims of delay, additional work, or other commercial claims, in all such cases arising after the Effective Date, by any third-party contractor having privity with Service Provider under a subcontract or purchase order listed on Exhibit H, Part B or a subcontract or purchase order the Owners direct the Service Provider to assume to permit Service Provider to perform the Services hereunder, or by such contractor's subcontractors, vendors or suppliers, performing work related to the Project. This Owners' indemnity obligation shall not apply to any claim arising out of Service Provider's, its subcontractors', or their Representatives' (a) failure to comply with applicable Law, (b) reckless or intentionally wrongful conduct, including activities or actions that Service Provider knows are contrary to Owners' written direction or position, which are not contrary to Law or the terms of this Agreement, or (c) actions other than those taken pursuant to this Agreement.

16.3 Notice of Third Party Claims . If any Person that is not a Party to this Agreement or an Affiliate of a Party to this Agreement notifies any Persons Indemnified with respect to any matter that may give rise to a claim for indemnification against Service Provider or Owners under this Agreement, then the Persons Indemnified shall promptly notify the indemnifying Party of all relevant details thereof then known to the Persons Indemnified. In the event that the Persons Indemnified fails to give prompt notice as stated above, the obligation to indemnify shall

be waived to the extent that said notice failure causes actual and material prejudice to the indemnifying Party's ability to defend the claim for which indemnity is requested. The Party providing the indemnity of any third-party claim shall have control of the defense of indemnified claims including the selection of defense counsel and settlement of all indemnified claims.

16.4 Intellectual Property Infringement .

(a) Service Provider shall indemnify, hold harmless, release and defend Owner Persons Indemnified from all losses which may be incurred on account of alleged or claimed infringement of any United States patent or United States copyright, or misappropriation of any trade secret, trademark rights, proprietary rights or other intellectual property rights of any third party, arising out of the performance of Services by Service Provider. Owners shall promptly notify Service Provider of such claims, suits and actions in writing and Service Provider shall pay all costs, expenses, settlements and/or judgments resulting therefrom.

(b) If a claim of infringement or misappropriation is made, Service Provider may, and if the Services provided hereunder by Service Provider are held by a court of competent jurisdiction to constitute an infringement or misappropriation of any United States patent or United States copyright, trade secret, trademark rights, proprietary rights or other intellectual property rights of any third party, and if the use of said Services is enjoined, Service Provider shall, at its sole expense, either: (a) procure for Owners the right to continue using said Services; or (b) modify the infringing Services so they become non-infringing, to the extent reasonably possible without diminishing the capability and capacity of the Services. In the event the above alternatives are unavailable to Service Provider, then, with the approval of Owners, Service Provider shall seek alternate ways and means to provide such Services for which it is obligated under this Agreement so long as such alternate means are reasonably acceptable to Owners.

(c) Notwithstanding the above, Service Provider shall not compromise or settle any claim, action, suit or proceeding in which Owners are named without Owners' prior written consent, which consent shall not be unreasonably conditioned, delayed or withheld unless such settlement provides for the payment of money only by Service Provider and provides for a full, complete and unconditional (other than ceasing Services) release of Owners.

(d) The foregoing indemnity shall not apply in situations where (i) the Services are furnished in accordance with designs supplied by Owner or to the extent any Service furnished hereunder is modified or combined by Owner or others with items not furnished hereunder, or (ii) Owners use the Services of Service Provider contrary to written instructions from Service Provider that specify in detail the use or uses of such Services which will constitute an infringement of any United States patent or United States copyright, or the violation of any trade secret, trademark right, proprietary right or other intellectual property right of any third party. In the event a suit or proceeding is brought against Service Provider as a result of such Owners' design modification or combination, or actions not approved by Service Provider, Owners will indemnify and hold Service Provider harmless to the same extent as

Service Provider has agreed to indemnify and hold Owners harmless hereunder; provided that Owners' indemnity obligations under this Section 16.4(d) will not be limited by Section 17.4.

(e) Any indemnities associated with third-party software shall be governed by the terms of the license agreements associated with such third-party software.

ARTICLE 17. LIMITATION OF LIABILITY

17.1 Limitations Applicable to Warranty Work.

(a) Equipment Warranty Cap. Service Provider's cumulative aggregate liability under all warranties applicable to Service Provider-manufactured equipment in Section 10.5(b) shall be five million dollars ($5,000,000).

(b) Professional Services Warranty Cap. Service Provider's liability for re-performance or repair in relation to defective professional services under Section 10.1 herein shall be limited to the insurance proceeds recoverable under the professional liability coverage required by Article 24.

17.2 Service Provider's cumulative aggregate liability to Owners under or related to this Agreement for any and all claims, losses, re-work warranty obligations, expenses, damages, suits, judgments, fines, penalties, or liabilities of any kind arising out of or in connection with this Agreement shall not exceed the total amount of the Fee paid to Service Provider as of the date the liability arose under this Agreement; provided, however, that the foregoing limitation in this Section 17.2 shall not apply to the following, which shall not be considered in determining whether such aggregate liability cap has been exceeded: any loss or damage, to the extent insurance proceeds are available from the insurance required under this Agreement, it being the Parties' specific intent that the limitations of liability hereunder shall not relieve the insurer's obligation for such insured risks.

17.3 Except for breaches of Article 14 or use of Intellectual Property outside the permissible license scope, under no circumstances shall either Party be liable to the Persons Indemnified of the other Party for consequential losses or damages, including, but not limited to, in the character of (a) loss of use of power systems, production facilities or equipment, (b) loss of profits or revenues, (c) loss of tax credits, (d) cost of purchased or replacement power, (e) damages suffered by customers for service interruptions, or (f) costs of financing.

17.4 Owners' Aggregate Liability Cap. Other than Owners' indemnity obligations hereunder, Owners' cumulative aggregate liability to Service Provider under this Agreement from any and all causes arising out of or in connection with this Agreement shall not exceed the total amount of payment actually paid and/or due to Service Provider in accordance with Exhibit C (Rates and Invoicing).

17.5 Springing License Exclusive Remedy. Upon the occurrence of a Triggering Event under Exhibit F (Facility IP License in the Event of a Triggering Event), Owners shall be entitled

to exercise their license rights thereunder. The provision of such a license on a royalty-free basis and the disclosure of Facility IP thereunder shall be Owners' sole and exclusive remedy and Service Provider's sole liability, with respect to the acts or omissions giving rise to the Triggering Event.

17.6 Limitations on liability expressed in this Article 17 shall apply even in the event of the fault, negligence, or strict liability of Service Provider or Owners, as applicable, or otherwise and shall extend to the Parties' directors, officers and employees, and to any affiliated entity of the Party hereto, and its directors, officers and employees.

ARTICLE 18. BENEFITED PARTIES

Service Provider understands and agrees that GPC is entering into this Agreement not only for its own benefit but also and equally for the direct benefit of Owners. By agreement, SNC has the right and obligation to construct, operate and maintain generating plants, which are owned jointly by GPC and the other Owners, and SNC has the right to enter into agreements for exercising said rights and performing said obligations. As their interests appear, it is further agreed that each and every right, benefit and remedy accruing to GPC likewise accrues to the Owners including but not limited to the right to enforce this Agreement in their own name or names. For the avoidance of doubt, each of Owners and SNC are Owner Persons Indemnified under this Agreement. Notwithstanding the foregoing, as between GPC, Owners, and Service Provider, GPC shall remit (on behalf of Owners) all payments to Service Provider hereunder, and Service Provider shall submit all invoices to GPC for payment. Owners represent that Owners are the sole present owners (subject to mortgage indentures) of the Facility to which the Services relate and that GPC is authorized to bind, and does bind, all present Owners to the limitations of liability set forth in this Agreement. In the event that any other entity obtains any ownership interest in a facility for which Services are performed, then Owners agree to bind such entity to such limitations of liability.

ARTICLE 19. DISPUTE RESOLUTION

19.1 A "Claim" is a demand or assertion by one of the Parties seeking, as a matter of right, adjustment or interpretation of Agreement terms, payment of money, extension of time, or other relief with respect to the terms of this Agreement. The term "Claim" also includes other disputes and matters in question between Owners and Service Provider arising out of or relating to this Agreement (including the breach, termination or validity thereof, and whether arising out of tort or contract).

19.2 All Claims not otherwise resolved by the Parties shall be submitted to and decided by arbitration before a three-member panel (the "Panel") pursuant to the then-current *e.g.* , CPR Rules for Expedited Arbitration of Construction Disputes and the Federal Arbitration Act, 9 U.S.C. §§ 1 *et seq* . The Panel members shall be mutually agreeable to the Parties and are as of the date of this Agreement Jesse B. Grove, David Lane and Richard Alexander. Upon any vacancy on the Panel, the Parties shall endeavor to agree on a replacement member promptly, notwithstanding whether any Claim then is pending.

19.3 Either Party may commence arbitration by providing written notice of a Claim to the other and to the members of the Panel. Such notice shall include a written statement of the

Claim along with substantiation for the Claim. The receiving Party shall respond with a statement of its position on the Claim and substantiation for its position within twenty-one (21) days of such notice.

19.4 No later than thirty (30) days after notice of a Claim, the Panel shall hold an initial pre-hearing conference for the planning and scheduling of the arbitration. The Panel may establish procedures and otherwise conduct the arbitration in such manner as it deems appropriate to assure an expeditious and fair resolution of the Claim. Unless extended by agreement of the Parties or by order of the Panel, in no event shall the Panel's final decision be issued later than one hundred eighty (180) days after notice of a Claim.

19.5 The place of the arbitration shall be Atlanta, Georgia.

19.6 The decision of the Panel is final and binding and is not subject to further arbitration or litigation by either Party.

19.7 Notwithstanding anything in this Article to the contrary, a Party may file a complaint in a court of competent jurisdiction to seek enforcement of the agreement to arbitrate set forth in this Article, other injunctive relief or specific performance, or enforcement of any decision or award issued by the Panel.

ARTICLE 20. TERMINATION

20.1 Owners, in their sole discretion, shall have the right to terminate this Agreement without cause by providing written notice to Service Provider at least thirty (30) days in advance of the date of termination or other minimally necessary time period such that Service Provider complies with federal and state notice requirements (e.g., WARN Act) as measured from the date of written notice of termination. In the event of such a termination, Service Provider shall be compensated in accordance with the terms of Section 20.3. In no event shall termination costs include such costs as loss of anticipated profit.

20.2 Either Party may terminate this Agreement on the basis of a material breach by written notice of breach where the breaching Party fails to cure the default within thirty (30) days. For the avoidance of doubt, Service Provider may terminate this Agreement in the event that Owner fails to make payment on any invoice within thirty (30) days after the due date of such invoice and Owner fails to cure the non-payment default within thirty (30) days.

20.3 Termination Costs . In the event of Owners' termination for convenience under Section 20.1, Service Provider shall recover from Owners, as complete, full, and final settlement for such terminated work, a sum equal to Service Provider's actual direct costs for work performed as of the termination date. In addition, Service Provider shall recover from Owners its reasonable and direct costs incurred to terminate its subcontracts and purchase orders that support the Project. Service Provider shall in no event be entitled to recover indirect, special,

incidental, consequential or exemplary damages, including but not limited to loss of profits or revenue on Services not performed. Service Provider shall also recover the following from the Owner in the event of termination for convenience:

(a) Direct costs for storage, transportation, insurance and other costs incurred, reasonably necessary for the preservation, protection, or disposition of the materials or equipment.

(b) Direct costs for demobilization, including removal of equipment or other materials, and personnel-related costs (i.e., internal administrative costs and severance (consistent with Westinghouse's and WECTEC's severance programs effective immediately prior to bankruptcy), but not liabilities or damages arising from Service Provider's release or termination of an employee or employees); and

(c) Any other costs approved in writing by Owners in advance of the termination date.

20.4 Service Provider shall not be paid for any Services performed by it or its subcontractors or costs incurred after receipt of a notice of suspension or termination, which Service Provider could reasonably have avoided, nor shall Owners be liable for any anticipated profits on Services not performed, or for any loss or damage with respect to any equipment, materials or property purchased or leased for anticipated use in the Services, unless such equipment, materials or property were specifically authorized by Owners. Payment as specified in this Article 20, and indemnity specified in Article 17, as applicable, shall be Service Provider's sole and exclusive remedies and Owners' sole and exclusive obligation and liability to Service Provider with respect to such termination.

20.5 Without limiting the terms of the Facility IP License in the Event of a Triggering Event (Exhibit F), from and after termination of this Agreement, Service Provider shall have no obligation to deliver any further Facility IP to Owners.

ARTICLE 21. ASSIGNMENT

Owners' consent shall not be required for Service Provider's assignment in connection with the Bankruptcy Cases of its rights or obligations under this Agreement; provided however, that the rights of Owners under the Bankruptcy Code are preserved in all respects. After the conclusion of the Bankruptcy Cases, Service Provider shall be entitled to assign its rights or obligations under this Agreement without prior approval of Owners. Owners shall not assign this Agreement in whole or in part without the prior written consent of Service Provider, which consent shall not be unreasonably withheld; provided, however, that this Agreement may be assigned in whole or part by the Owners to any agent, replacing GPC as agent for the Owners, pursuant to the provisions of the Ownership Agreement; and provided further that any Owner shall be permitted to assign this Agreement to another Owner or to an Affiliate in accordance with the Ownership

Agreement or to any purchaser or any Financing Parties in connection with the transfer of control or ownership of the Facility.

ARTICLE 22. GOVERNING LAWS AND REGULATIONS, VENUE, AND COMPLIANCE WITH LAWS

22.1 With acknowledgment that the terms and conditions of this Article 22 have been expressly bargained for and are an essential part of this Agreement, the Parties agree that this Agreement will be governed by and interpreted in accordance with the laws of the State of New York, without giving effect to any choice-of-law rules that may require the application of the laws of another jurisdiction. The Parties agree that the exclusive jurisdiction and venue for any action relating to this Agreement shall be as provided in Article 19. To the extent allowable under this Agreement, for any suit or action in a court of law relating to this Agreement, the Parties agree that the exclusive jurisdiction (personal and, as allowed, subject matter) and venue for any action relating to this Agreement shall be the United States District Court for the District of Columbia, and the Parties hereby consent to such jurisdiction and venue. Owners and Service Provider each hereby irrevocably waive their respective rights to a trial by jury in any action or proceeding arising out of this Agreement.

22.2 Service Provider represents that in performing the obligations of this Agreement, all applicable federal, state and local laws and regulations and Executive Orders of the President of the United States have been and will be complied with by Service Provider and its Representatives.

22.3 Without limiting the generality of the foregoing obligation, Service Provider agrees that it is responsible for obtaining all applicable permits, licenses, or other Governmental Approval necessary for and unique to Service Provider’s performance of the Services. Service Provider will adhere to applicable Laws including for example: (i) all labor laws and regulations including the use of U.S. citizens or properly documented alien workers under the Immigration Act of 1990 and the Immigration and Nationality Act of 1952, as amended; (ii) all applicable safety and health standards required by the NRC, the Atomic Energy Act of 1954, as amended, and the ERA, as well as all applicable safety and health standards promulgated under the OSHA of 1970, including but not limited to OSHA General Industry Regulations 1910.269 and 1926 Subpart V and all applicable state or local health or safety authority with jurisdiction over the Services performed or to be performed under this Agreement; (iii) the Department of Homeland Security’s E-Verify requirements as well as applicable State immigration laws; (iv) the Foreign Corrupt Practices Act, 15 U.S.C. §§ 78dd-I et seq. (as that act may be amended from time to time); (v) the Department of Energy’s regulations, including but not limited to the protection of special nuclear material and sensitive nuclear technology; and (vi) all applicable laws and regulations identified in this Agreement. Service Provider expressly agrees to indemnify, defend and hold harmless the Owner Persons Indemnified from and against all claims, fines or penalties of every kind and nature presented or brought for any claim or liability arising from or based on the violation of any Law on the part of Service Provider or its Representatives.

22.4 Each Party hereby represents and warrants as follows at all times during the term of this Agreement: (i) all of its activities are authorized and in compliance with and not prohibited by 10 C.F.R. Part 810; (ii) neither it, nor any of its employees, authorized agents, subcontractors, principals or beneficial owners is a Specially Designated National as defined by U.S. Department of the Treasury Office of Foreign Asset Control ("OFAC"); (iii) neither it, nor any of its employees, authorized agents, subcontractors, principals or beneficial owners, is a citizen of a country subject to an OFAC Country Sanction; and (iv) it, and all of its employees, authorized agents, subcontractors, principals or beneficial owners, are in compliance with any and all applicable Laws and regulations relating to the prevention of money laundering and the financing of terrorism to which they are expressly subject.

22.5 Certain Owners are government contractors under an Area Wide Public Utilities Contract with the General Services Administration of the United States government. Service Provider agrees that each of the clauses contained in the Federal Acquisition Regulations referred to below, shall, as if set forth herein in full text, be incorporated into and form a part of this Agreement, and Service Provider shall comply therewith if the amount of this Agreement and the circumstances surrounding its performance require such Owner to include such clause in contracts between such Owner and others:

(1) 52.203-3 Gratuities (APR 1984);
(2) 52.203-6 Restrictions on SubService Provider Sales to the Government (SEP 2006);
(3) 52.203-7 Anti-Kickback Procedures (MAY 2014);
(4) 52.219-8 Utilization of Small Business Concerns (OCT 2014);
(5) 52.219-9 Small Business Subcontracting Plan (OCT 2014);
(6) 52.222-21 Prohibition of Segregated Facilities (FEB 1999);
(7) 52.222-26 Equal Opportunity (MAR 2007);
(8) 52.222-37 Employment Reports on Veterans (JUL 2014);
(9) 52.222-40 Notification of Employee Rights under the National Labor Relations Act (DEC 2010);
(10) 52.222-50 Combating Trafficking in Persons (FEB 2009);
(11) 52.222-54 Employment Eligibility Verification (AUG 2013); and
(12) 52.225-13 Restrictions on Certain Foreign Purchases (JUN 2008).

22.6 If Service Provider is subject to the requirements set forth in Federal Acquisition Regulations 52.219-9, Service Provider will (i) adopt a subcontracting plan ("Plan") that complies with the requirements of 52.219-9; (ii) provide a written copy of the Plan to Owners, and (iii) upon written request, provide timely periodic reports to Owners that reflect the amounts paid to subcontractors who are a small business concern, veteran-owned small business concern, service-disabled veteran-owned small business concern, HUBZone small business concern, small disadvantaged business concern, or women-owned small business concern.

22.7 Service Provider represents and warrants that Service Provider is not debarred, suspended or proposed for debarment to any department, agency or other division of the United

States government. In the event that Service Provider or any of its officers become debarred, suspended or proposed for debarment during the term of this Agreement, Service Provider will immediately notify Owners verbally and in writing.

22.8 Service Provider certifies that no federal funds have been paid or will be paid to any Person including any registered lobbyists for influencing or attempting to influence an officer or employee of any Federal agency in connection with this Agreement or subsequent amendments of this Agreement.

22.9 Davis-Bacon Act Required Contract Clauses .

(a) The contract clauses contained under the heading "Davis-Bacon Act Required Provisions" in Exhibit J-1 (Davis-Bacon Act Required Provisions) to this Agreement shall, as if set forth herein in full text, be incorporated into and form a part of this Agreement, and Service Provider shall comply therewith if the amount of this Agreement and the circumstances surrounding its performance require any Owners to include such clauses in this Agreement.

(1) The Parties will cooperate in seeking appropriate exemptions from disclosure under the Freedom of Information Act, 5 U.S.C. § 552, and associated regulations for certified payroll data provided to federal agencies in the course of compliance with the Davis-Bacon Act and the Davis-Bacon Act regulations.

(2) Where necessary and required by law, Service Provider will support Owners with the maintenance of the DAVIS-BACON AND RELATED ACTS COMPLIANCE PROGRAM FOR VOGTLE UNITS 3&4 PROJECT.

(b) The wage determinations set forth in Exhibits J-2 through J-5 are applicable to Services provided under this Agreement.

ARTICLE 23. EQUAL EMPLOYMENT OPPORTUNITY

23.1 Owners comply with all applicable federal and state fair employment Laws, including, without limitation, Title VII of the Civil Rights Act of 1964, the Age Discrimination in Employment Act of 1967, the Americans with Disabilities Act of 1990, all provisions of Executive Order 11246, as amended, 41 C.F.R. § 60-1, and all of the rules, regulations and relevant orders of the Secretary of Labor. Owners prohibit any acts of discrimination, or illegal harassment on the basis of race, color, religion, age, disability, veteran status, gender, sex, sexual orientation, gender identity, national origin or any other basis prohibited by law. Owners are committed to taking affirmative action as required by Law and to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, gender, color, religion, age, national origin, disability, veteran status, or any classification protected by federal, state or local law. Such action includes, but is not limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including

apprenticeship. Owners will post in conspicuous places, available to employees and applicants for employment, all legally required notices stating that all qualified applicants will receive consideration for employment without regard to race, color, religion, age, national origin, sex, sexual orientation, gender identity, disability, or veteran status.

23.2 Service Provider will comply with all applicable federal and state fair employment Laws, including, without limitation, Title VII of the Civil Rights Act of 1964, the Age Discrimination in Employment Act of 1967 and the Americans with Disabilities Act of 1990, and all provisions of Executive Order 11246, as amended, 41 C.F.R. § 60-1, and all of the rules, regulations and relevant orders of the Secretary of Labor. Service Provider will not discriminate against any employee or applicant for employment because of race, color, religion, age, disability, veteran status, genetic information, sex, sexual orientation, gender identity, national origin, or any classification protected by federal, state or local law. Service Provider shall take affirmative action as required by law and to ensure that applicants are employed, and that employees are treated during employment without regard to their race, gender, color, religion, age, national origin, disability, veteran status, or any classification protected by federal, state or local law. Such action will include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. Service Provider agrees to post in conspicuous places, available to employees and applicants for employment, all government required notices stating that all qualified applicants will receive consideration for employment without regard to race, sex, sexual orientation, gender identity, color, religion, age, national origin, physical handicap, or veteran status.

23.3 In accordance with the U.S. Department of Labor’s regulations implementing the Vietnam Era Veterans Readjustment Assistance Act, as amended, at 41 C.F.R. Part 60-300, Owners and Service Provider shall abide by the requirements of 41 C.F.R. § 60-300.5(a). This regulation prohibits discrimination against qualified protected veterans and requires affirmative action by covered prime Service Providers and subcontractors to employ and advance in employment qualified protected veterans.

23.4 In accordance with the U.S. Department of Labor’s regulations implementing Section 503 of the Rehabilitation Act of 1973, as amended at 41 C.F.R. Part 60-741, Owners and Service Provider shall abide by the requirements of 41 C.F.R. § 60-741.5(a). This regulation prohibits discrimination against qualified individuals on the basis of disability and requires affirmative action by covered prime contractors and subcontractors to employ and advance in employment qualified individuals with disabilities.

ARTICLE 24. INSURANCE

24.1 Service Provider-Furnished Insurance for Off-Site Activities. Service Provider (and its subcontractors, if any) shall provide and maintain in effect during performance of the Services the following insurance with minimum limits as specified for each type of insurance to cover off-Site activities:

(a) Workers' Compensation Insurance in accordance with statutory requirements and Employer's Liability Insurance with limits not less than $1,000,000. Coverage should include claims for applicable workers' compensation, occupational disease, personal injuries, and death to Service Provider's employees in amounts required by statute.

(b) Commercial General Liability Insurance, including with limits not less than $2,000,000 each occurrence, and annual aggregate, and including broad form contractual coverage, product liability and one (1) years' completed operations coverage, broad form bodily injury and property damage coverage. Any deductible or self-insured retention cost shall be for the account of Owners, but such deductible or self-insured retention cost shall not exceed $250,000.

(c) Excess Liability or Umbrella Liability Insurance for Bodily Injury and Property Damage Liability with $5,000,000 combined single limit each occurrence and in the aggregate. Any deductible shall be for the account of Service Provider. Any excess liability or umbrella policy will be applicable to the general liability, auto liability and employer's liability policies that are required.

(d) The Commercial General Liability and the Excess Liability or Umbrella Liability insurance coverages must name the Owners Persons Indemnified as well as their respective officers, directors, employees, agents, and representatives as additional insureds with respect to liability arising out of Services performed by or on behalf of Service Provider under this Agreement; provided that Service Provider's insurance will not provide coverage for injury or damages to the extent resulting from the sole negligence of the Owners Persons Indemnified.

(e) Other insurance as may be mutually agreed upon by the Parties.

24.2 Professional Liability. Service Provider will make all commercially reasonable efforts to maintain and renew as necessary its professional liability coverage currently in place. At Owners' option, Owners and Service Provider will cooperate to obtain professional liability coverage in addition to that already in place, or if necessary to replace Service Provider's existing professional liability coverage. Service Provider will maintain such professional liability coverage at Owners' expense.

24.3 Service Provider's Property. Service Provider will be responsible for providing and maintaining property insurance coverage, to the extent such property is not a permanent part of the finished Project and not covered by a separate Builder's Risk Insurance Policy provided and maintained by Owners pursuant to Section 24.11.

24.4 Automobile Liability Coverage. Service Provider will be responsible for providing and maintaining Comprehensive Automobile Liability insurance, including coverage for owned, hired and non-owned automobiles, with a combined single limit not less than $2,000,000 per occurrence.

24.5 Service Provider shall use commercially reasonable efforts to ensure the insurance required by Sections 24.1, 24.2, 24.3 and 24.4 shall contain a waiver of subrogation by Service Provider's (or any subcontractor's) insurance carrier against Owners and its insurance carrier with respect to all obligations assumed by Service Provider pursuant to this Agreement. All such insurance shall be with sound insurance companies. The liability policies under Section 24.1(b) shall not have any "other insurance" clause or language which would jeopardize the primacy of Service Provider's insurance with respect to the Owners' self-insured retention or excess insurance policies.

24.6 Service Provider shall require its insurer(s) to issue endorsements (if required) to add Owners, their subsidiaries, associated and/or affiliated companies, their successors and assigns, SNC and Southern Company Services, Inc., and the officers, directors, agents and employees of any of them, as additional insureds on Service Provider's off-Site policies, established pursuant to Section 24.1, and Service Provider's Automobile Liability Coverage, established pursuant to Section 24.4.

24.7 Service Provider must notify Owners at least thirty (30) days before the effective date of any cancellation (and ten (10) days due to nonpayment of premium) of any of the required policies.

24.8 Service Provider agrees to submit to Owners Certificates of Insurance evidencing the coverage prescribed by this Agreement and the expiration date(s) of each applicable policy. All such requested Certificates of Insurance will be submitted to Owners. In no event, however, will Owners' collection and review of such certificates (or decision not to collect and review such certificates) create any responsibility on the part of Owners to verify the appropriateness and validity of Service Provider's insurance, to notify Service Provider with regard to any matter related to its insurance, or to ensure that the insurance requirements above have been satisfied; nor does such collection and retention create a waiver by Owners of any of their rights in connection with such insurance.

24.9 Owner-Controlled Insurance Program. Owners will provide Service Provider with Workers' Compensation Insurance, Commercial General Liability Insurance and Excess Liability Insurance for Services performed on-Site through its Owner-Controlled Insurance Program ("OCIP"). If at any time the OCIP is not maintained, Service Provider will be responsible for maintaining coverage identical to the coverage listed in Section 24.1.

24.10 Nuclear Insurance.

(a) Owners will maintain insurance to cover the legal obligation to pay damages because of bodily injury or property damage caused by a Nuclear Incident, as that term is defined under the AEA, such policy to be provided by American Nuclear Insurers or the equivalent. The insurance will be in such form and in such amount to meet the financial protection requirements of NRC regulations and the AEA. As provided by the AEA, Service Provider and its subcontractors shall be included among the insureds or persons protected under the financial protection arrangements in the AEA.

(b) Owners will maintain a governmental indemnity agreement pursuant to NRC regulations and the AEA.

(c) In the event that the financial protection system contemplated by Section 170 of the AEA is repealed or changed, Owners will maintain in effect, during the period of operation of the Facility, liability protection through governmental indemnity, limitation of liability and/or insurance which takes into account the availability of insurance, customary practice in the United States electric utility industry for plants of similar size and character, and other relevant factors in light of the then existing conditions.

(d) As required by the NRC, the foregoing financial protection, indemnification agreement, and insurance will be maintained in effect from the time nuclear fuel or materials first arrive at the Site.

24.11 Property Insurance. Owners will also maintain such property insurance, including an insurer's waiver of subrogation in favor of Service Provider, its subcontractors and suppliers, as is available at a reasonable cost and on reasonable limits from Nuclear Electric Insurance Limited, or other sources consistent with the regulations of the NRC and the current industry practice, providing protection against direct physical loss or damage to the Facility. Subject to Article 17 hereunder (Limitation of Liability), any deductible amount under such property insurance that may be applicable to any damage to the property of Owners will be borne by Owners. Owners waive any right of recovery from Service Provider, its subcontractors or suppliers for damage to any property located at the Site arising out of a Nuclear Incident as that term is defined under the AEA.

24.12 Employees' Claims. Service Provider will promptly inform Owners in writing of any employee's claim, whether workers' compensation, tort liability or otherwise, for bodily injury allegedly caused by a nuclear energy hazard arising out of the Project, or during the course of transporting nuclear material from the Project. Service Provider's written notice will provide the following information:

Name and address of claimant;
Time and place of alleged exposure to nuclear energy hazard, if known; and
Description of alleged bodily injury.

The notice is to be addressed to:

Southern Nuclear Operating Company, Inc.
Attention: Director, Supply Chain Management
Post Office Box 1295
Birmingham, Alabama 35201

ARTICLE 25. UNFORESEEABLE CONDITIONS

Neither Party hereto shall be considered in default in the performance of its obligations hereunder to the extent that the performance of any such obligation is delayed due to acts of God, acts of civil or military authority, governmental priorities, fires, labor disputes, strikes (but not including strikes of Service Provider's employees unless part of a nationwide or sector-wide strike), acts of the public enemy, floods, epidemic, war, riot, or like occurrences, provided such occurrences are beyond the control, and without the fault, of the Party seeking excuse hereunder; provided however that Owners' payment obligations shall not be subject to any excuse for unforeseeable conditions. Any Party seeking excuse under this Article 25 shall promptly notify in writing the other Party of its delay and take all reasonable steps to mitigate the effect of such delay on the other Party, except that any Party shall have the right to settle its strikes or labor disputes in its sole discretion. The Party claiming excuse shall resume its obligations as soon as practical. The unaffected Party may take any actions available under this Agreement or available by law to mitigate or resolve the cause of the claimed excuse.

ARTICLE 26. CYBER SECURITY PROGRAM REQUIREMENTS

26.1 Protection of Digital Computer and Communication Systems and Networks. Service Provider understands that Owners are required under 10 C.F.R. § 73.54 to assure all Services performed related to digital computer and communication systems and networks are adequately protected against cyber-attacks, including the design basis threat described in 10 C.F.R. § 73.1, or Services associated with (i) safety-related and important-to-safety functions, (ii) security functions, (iii) emergency preparedness functions, and (iv) support systems and equipment which if compromised, would adversely impact safety, security, or emergency preparedness functions. Service Provider agrees that all related Services performed by Service Provider will be performed in compliance with Owners' cyber security plan.

26.2 Procurement of Services. When providing cyber security related Services or any Services on critical digital assets (hardware, firmware, operating systems, or application software) at Owners' facilities, such Services will be subject to the controls of the Service Provider's Quality Assurance Program including the Quality Assurance Interface Agreement, including as follows (provided that in the event of a conflict, Owners' Quality Assurance Program requirements will control):

(a) Service Provider, before beginning permitted access to Owners' network, will be made aware of and trained on Owners' Quality Assurance Program and must agree to abide by the relevant policies; and Service Provider will at all times remain responsible for the compliance of its authorized Representatives and sub-tier contractors.

(b) Service Provider will participate in Owners' cyber security training programs or equivalent qualification from Service Provider, subject to Owners' approval of such qualification.

(c) Service Provider will require:

(i) configuration management of the Service Provider's computers, hardware or other equipment to include virus protection, patch management, authentication requirements and secure internet connections;

(ii) the maintenance and secure transfer and storage of information and code while off-Site to include appropriate encryption, security and deletion protocols;

(iii) a duty to protect confidentiality;

(iv) software quality assurance ("SQA") procedures;

(v) approved and disapproved software requirements tabulation;

(vi) processes and procedures for background investigations; and

(vii) Owners' right to audit or access Service Provider's cyber security program.

ARTICLE 27. COMPLIANCE WITH SITE AND SECURITY RULES AND POLICIES

27.1 Throughout the term of this Agreement, whenever any Service Provider Representatives are at the Site, Service Provider and its Representatives shall comply with all applicable rules, regulations, policies, programs, procedures and other requirements of Owners, including, but not limited to, applicable requirements relating to site, security, FFD, quality concerns, quality control, quality assurance, safety, radiation protection and control, environmental compliance and regulatory compliance, and electronic communications (collectively, "Site Rules"). If at any time during the term of this Agreement, Service Provider or its Representatives fail to comply with Owners' Site Rules, Owners reserve the right to exercise all their legal remedies including the right to refuse Site entry to or have removed from the Site Service Provider or its Representatives. It is Owners' expectation that these Site Rules be communicated by Service Provider to its Representatives before they are granted access to any of Owners' locations.

27.2 Asbestos Responsibility. Certain areas for which Service Provider has contracted to perform work may contain asbestos. As used in this Section 27.2, the term "asbestos" includes "asbestos-containing material" and "presumed asbestos-containing material", as these terms are defined in 29 C.F.R. § 1926.1101 and 29 C.F.R. § 1910.1001. Areas within the Site which are known by Owners to contain asbestos are posted. It is Service Provider's responsibility to exercise caution while at the Site in light of the potential that the area in which Service Provider is working may contain asbestos. Service Provider shall take the following precautions, unless advised otherwise in writing by Owners: (1) Service Provider must check for postings in the area, and (2) Service Provider must be sensitive to the potential that asbestos might exist. If Service Provider determines that there is a potential that asbestos exists in the work area or

component, Service Provider shall immediately stop work and notify Owners to investigate the potential asbestos-containing material to determine if, in fact, the material contains asbestos. If the material is found to be asbestos, Service Provider must coordinate any related Services with Owners. Under no circumstances shall work continue when asbestos is discovered without the specific approval of Owners. Unless authorized in writing by Owners in advance, Service Provider shall not use asbestos in the Facility.

27.3 Service Provider will obtain from Owners all Site Rules and procedures and educate its Representatives concerning such Site Rules and procedures before any of its Representatives enter any of Owners' premises. Service Provider acknowledges that its Representatives may be required to successfully complete indoctrination classes and similar instructional classes concerning such procedures before admission to, or the performance of Services on, Owners' premises.

27.4 Owners have a zero tolerance policy on firearms being brought onto Owners' property. Under no circumstance is a Service Provider employee, agent, or Representative to bring firearms, explosives or any other incendiary devices onto any property owned or operated by Owners. This prohibition includes leaving such items in a vehicle that is parked in Owners' parking lot. Violation of this policy could result in Service Provider or its Representatives being barred from all property owned or operated by Owners or their Affiliates.

27.5 Safety. Service Provider will be solely responsible for conforming to safety practices dictated by the nature and condition of the Services while at the Site, including compliance with OSHA of 1970. Service Provider and its Representatives must be trained in accordance with applicable OSHA Standards. Within a reasonable time following a specific request by Owners, Service Provider shall provide Owners copies of training records for its Representatives concerning a particular safety and health standard and/or particular substantive or technical training requirement of the job.

27.6 Reporting of Accidents and Noncompliance with Safety Requirements. Service Provider will promptly report to Owners, on such form and in such detail prescribed below, all accidents causing, or having the potential to cause, personal injury or property damage and other unsafe acts or conditions, arising from or otherwise connected with performance of the Services at the Site or Owners' premises. In the event Owners provide written notification to Service Provider of any noncompliance with the provisions of this Section 27.6, Service Provider shall take corrective action promptly in a manner acceptable to Owners. Owners will not be obligated to identify, and notify Service Provider of, noncompliance with this Section 27.6 and any failure by Owners to identify, and notify Service Provider of, such noncompliance will not relieve Service Provider of any obligation or liability under this Agreement.

27.7 Medical/Injuries Reporting. Owners shall provide first aid to Service Providers Representatives on-Site. Injuries that require treatment beyond first aid will follow Owners' emergency response procedures.

27.8 Service Provider shall immediately notify Owners of any recordable injury or potential serious hazard to personnel on the job site. Service Providers shall submit a detailed, written report to Owners within forty-eight (48) hours of the recordable injury or serious incident. The injury report will contain the following information:

- Name of injured person and employee identification number,
- Date of injury,
- Names of any witnesses and employee identification numbers,
- Accident description,
- Cause of accident as evident at the time,
- Action taken to prevent re-occurrence, and
- Nature/Extent of injury.

All Service Provider personnel requiring medical attention on the Site or as a result of or relating to the Services performed on the Site will be drug screened by Owners as soon as possible and the test results must be forwarded to the designated Owners' Representative.

Service Provider shall post and keep current its OSHA Log at their on-Site office while Service Provider is performing Services for Owners. A copy of this OSHA Log will be provided to Service Provider representatives upon request.

Owner's Representative is responsible for reporting all serious incidents, injuries, and occupational illnesses that occur on-Site to Service Provider's Representatives. Owners shall perform an investigation, and a Service Provider's representative may participate in the investigation as determined by Owners' management and Service Provider. The investigation results and corrective actions must be provided to Service Provider, and Service Provider reserves the right to require additional corrective measures.

For clarity, the above reporting obligation and other requirements of this Section 27.8 shall only arise in connection with the performance of Services at or on Owners' property.

27.9 In the event that Service Provider requires access to the Vogtle Units 1 and 2 site, Service Provider will comply with all requests by Owners to facilitate such access, as required by NRC regulations and Owners' procedures. Owners reserve the right, in preparation for the declaration of a protected area for the Project, to specify additional requirements with respect to Fitness for Duty and access authorization, with the consent of Service Provider which consent will not be unreasonable withheld.

ARTICLE 28. FITNESS FOR DUTY

28.1 The NRC's Fitness For Duty regulatory requirements, codified in 10 C.F.R. Part 26, require licensees authorized to construct and operate nuclear power reactors to implement an FFD program that includes contract personnel such as Service Provider and its Representatives. Service Provider agrees that, by performing hereunder, Service Provider accepts and shall strictly adhere to the following requirements that:

(a) Service Provider will adhere to Owners' FFD program;

(b) Service Provider and its Representatives will provide support to Owners in connection with Owners' FFD program, including without limitation making personnel available and providing documents and information reasonably requested by Owners;

(c) Service Provider Representatives who have been denied access or have been removed from activities within the scope of 10 C.F.R. Part 26 at any nuclear power plant for violation of the FFD policy will not be assigned to work within the scope of 10 C.F.R. Part 26 without the knowledge and consent of Owners;

(d) Service Provider supervisory Representatives, to the extent that they are covered by 10 C.F.R. Part 26, will be trained in techniques and procedures for initiating appropriate corrective action;

(e) Owners are responsible to the NRC for maintaining an effective FFD program and that duly authorized representatives of the NRC may inspect, copy or take away copies of reports related to the implementation of Owners' FFD program under scope of contracted activities;

(f) Service Provider Representatives responding to work at Owners' facilities shall be fit for duty within the scope of 10 C.F.R. Part 26 and able to fully perform the assigned work activities; and

(g) all Service Provider Representatives shall report to work physically able to perform their job duties and that the Service Provider shall consider the scope of work required for each contract employee and the physical and mental requirements for each job (e.g., ladder climbing; work at elevations; working in extreme temperatures; heavy lifting; prolonged walking/standing; cognitive ability). Prior to an assignment under this Agreement, the Service Provider shall exercise due diligence to ensure that its Representatives who have pre-existing medical conditions that might contraindicate their work in these environments are appropriately evaluated prior to assignment.

ARTICLE 29. EMPLOYEE PROTECTION

29.1 To the extent required by Law, Service Provider and its personnel shall comply with the requirements of Section 211, "Employee Protection," of the Energy Reorganization Act of 1974, 42 U.S.C. § 5851, as amended; 10 C.F.R. § 50.7, "Protection of Employees Who Provide Information" and 29 C.F.R. Part 24.

29.2 Service Provider and its Representatives will maintain a safety conscious work environment ("SCWE") in which all employees feel free to raise concerns without fear of harassment, intimidation, retaliation or discrimination.

29.3 Service Provider and its Representatives will be subject to Owners' programs and procedures at all locations where Services under this Agreement are being performed to advise their personnel that they are entitled and encouraged to raise safety concerns to their management, to Owners, and to the NRC without fear of discharge or other discrimination. Owners' programs to which Service Provider and its Representatives are subject will include a Project Employee Concerns Program ("Project ECP") and a Project Corrective Action Program ("Project CAP"). The Project ECP and Project CAP will be reflected in written policies and procedures that employees may use to raise their concerns, and availability of the Project ECP and Project CAP will be broadly communicated. At the request of Owners and for the purposes of Owners' administration of the Project ECP, Service Provider will provide access to its personnel, and non-privileged documentation and records, as well as provide support Services on an as-needed basis (provided Service Provider has the available personnel). At the request of Owners and for the purposes of Owners' administration of the Project ECP, Service Provider will provide access to Service Provider's proprietary ECP policies and procedures for the limited purposes of transitioning to a Project ECP and, after the transition to a Project ECP is complete, Owners shall have access only in the event that such access is necessary for Owners to comply with any regulatory obligation or to administer any Project ECP investigation. Service Provider will provide Owners' Project ECP personnel with access to Service Provider's Vogtle Site-related non-privileged ECP records for Owners' use in maintaining and administering the Project ECP. For those ECP records generated prior to the Effective Date, Service Provider's obligation to provide ECP records is limited to those records relevant to Owners' administration of a Project ECP investigation or Owners' administration of a referred allegation from the NRC and Service Provider reserves the right to withhold records which, in the opinion of Service Provider's legal counsel, should be withheld.

29.4 As part of its employee training program for employees at Owners' Site, Service Provider will provide training to its employees regarding requirements of Section 211 of the ERA, 10 C.F.R. § 50.7, and NRC's Form 3. Employee training must also include information on Nuclear Safety Culture and SCWE. Owners shall have the right to audit training materials and the effectiveness of such training not less than every twelve (12) months during the term of this Agreement.

29.5 All employment decisions for Service Provider's employees will be made by Service Provider. Owners are not a joint employer with Service Provider and do not direct or

control Service Provider's employees, except those seconded to Owners. Consistent with the confidentiality requirements of its own ECP, Service Provider will promptly notify Owners' Project ECP representative of any allegation or complaint made by any Service Provider employee of harassment or intimidation under Section 211 of the ERA and 10 C.F.R. § 50.7 regarding the Project, or any investigation or proceeding relating to such an allegation or complaint. Service Provider will inform Owners promptly of any significant investigatory activity by the NRC and any enforcement action by the NRC related to any such allegation or complaint of harassment or intimidation under Section 211 related to the Project. If Service Provider takes any adverse employment action, limited to termination or demotion, of any Service Provider personnel involved in such allegation or complaint Service Provider will provide notification to Owners' legal counsel of such adverse employment action contemporaneously with notification to the affected personnel. Nothing in this Section 29.5 shall limit Owners' access to records and documentation related to such allegation or complaint in the event that such access is necessary for Owners to comply with any regulatory obligation.

29.6 Within two (2) business days of Service Provider's ECP's receipt of a nuclear safety or quality concern relating to the Services at the Project, Service Provider will provide notice of such concern to the Project ECP representative at the Vogtle site or corporate office. Service Provider will also ensure associated records and reports are maintained in accordance with applicable retention policies as specified by NRC regulations and provide a copy of such non-privileged records, with the exception of Service Provider's proprietary ECP policies and procedures which shall be available per Section 29.3, at the request of the Project ECP representative.

29.7 Service Provider agrees to indemnify and hold harmless the Owner Persons Indemnified from any claims by Service Provider's employees (except for those seconded to Owners) and associated costs (including costs of defense, attorney's fees and court costs), expenses, fines, penalties or other liability arising solely from conduct of Service Provider or its Representatives found to be in violation of Section 211 of the ERA or 10 C.F.R. § 50.7.

29.8 In accordance with 10 C.F.R. § 50.7, this Agreement does not in any way prohibit or restrict or otherwise discourage the free flow of information from Service Provider or its Representatives to the NRC. Further, any associated subcontract affecting the terms, compensation, conditions and privileges of employment will not contain any provision which prohibits, restricts or otherwise discourages the free flow of information to the NRC.

ARTICLE 30. NO TOLERATION OF UNACCEPTABLE BEHAVIORS

30.1 The Parties and their Representatives shall at all times conduct their business activities pursuant to this Agreement in an ethical manner and in compliance with all applicable laws and regulations. Representatives shall not, at any time, exhibit the following behaviors:

(a) Harassment or unlawful discrimination of any kind or character, including but not limited to conduct or language derogatory to any individual, race, color, religion, age, disability, veteran status, genetic information, sex, sexual orientation, gender

identity, national origin, or any classification protected by federal, state or local law, that creates an intimidating, hostile or offensive working environment. Specific examples include, but are not limited to, jokes, pranks, epithets, written or graphic material, or hostility or aversion toward an individual or group on the basis of a legally protected status.

(b) Any conduct or acts such as threats or violence that creates a hostile, abusive, or intimidating work environment. Examples of such inappropriate behaviors include, but are not limited to, fighting, abusive language, inappropriate signage, use or possession of firearms on Owners' property, and destruction of any Party's or any Party's employee property at the worksite or the threat of any of the foregoing.

(c) Service Provider's practices that are unsafe or harmful to the natural environment.

(d) Use of Owners' or Service Provider's computers, email, telephone or voice-mail system that in any way involves material that is obscene, pornographic, sexually oriented, threatening, or otherwise derogatory or offensive to any individual, race, color, religion, age, disability, veteran status, genetic information, sex, sexual orientation, gender identity, national origin, or any classification protected by federal, state or local law.

(e) The use of, being under the influence of, or possession of alcoholic beverages or unlawful drugs on Owners' property.

(f) Engagement in any activity that creates a conflict of interest or appearance of the same, or that jeopardizes the integrity of Owners or Service Provider (including but not limited to providing gifts and gratuities to Owners' employees).

(g) Posting in any social media forum (Facebook, Twitter, blogs, etc.) or communicating in any other public setting in a manner that does not constitute protected speech or protected activity and violates any of the provisions of this Agreement, regardless of whether those postings or communication are made using Owners' resources, Service Provider resources, or any Representative's resources, during or outside of work hours. Examples include, but are not limited to, divulging Confidential and Proprietary Information or making harassing or discriminating statements about, or directed at, employees or customers of Owners or its Affiliates or Service Provider or its Affiliates. No Representative will imply or in any way indicate that he/she speaks on behalf of Owners or its Affiliates or Service Provider or its Affiliates in any social media forum or any other public setting. Each Party reserves the right to monitor all communication made by anyone on such Party's equipment, including laptops, cellular telephones, and portable computing devices (*e.g.* , Blackberry, Smart Phones) and no Person has any reasonable expectation of privacy in such communications. Each Party's right to monitor includes, but is not limited to, the right to archive, store, and forensically recover electronic communications on such Party's equipment.

30.2 Owners and Service Provider shall communicate these required behaviors to all Representatives that work on the Project. If a Service Provider Representative observes an Owners' employee doing or is ever asked by an Owners' employee to do something the Representative considers to be unethical, illegal, or in violation of these behavior standards, Owners expect Service Provider to notify Owners' management immediately.

ARTICLE 31. NON-ENGLISH SPEAKING SERVICE PROVIDER WORKERS

31.1 Service Provider shall at all times assure that an English speaking Representative of Service Provider is provided for non-English speaking Service Provider Representatives and its subcontractors ("Service Provider Workers"). The Representative must have the ability to communicate with and translate the foreign language of all nonEnglish speaking Service Provider Workers to assure that the ability to communicate vital information is readily available. If the non-English speaking Service Provider Workers are divided into work groups, it shall remain the responsibility of the Service Provider that an English speaking Representative of Service Provider is provided so as to assure that the ability to communicate vital information is still readily available to all non-English speaking Service Provider Workers. Service Provider represents and warrants that it has communicated and translated to its non-English speaking Service Provider Workers including all information and training required by applicable laws and regulations and all other safety and health requirements, in addition to all job related duties. These requirements include but are not limited to OSHA of 1970, the Service Provider's Safety Program, the contract documents including contract safety requirements, any relevant manufacturer's information such as Material Safety Data Sheets, and the specific project safety plan for the work to be performed for Owners, in addition to any relevant hazards and special Site conditions that Owners have notified Service Provider may be encountered by Service Provider and/or its Service Provider Workers .

31.2 Service Provider represents and warrants that it has communicated and translated to its non-English speaking Service Provider Workers including all information and training required by applicable laws and regulations and all other safety and health requirements, in addition to all job related duties. These requirements include but are not limited to OSHA of 1970, the Service Provider's Safety Program, the contract documents including contract safety requirements, any relevant manufacturer's information such as Material Safety Data Sheets, and the specific project safety plan for the work to be performed for SNC, in addition to any relevant hazards and special Site conditions that SNC has notified Service Provider may be encountered by Service Provider and or its Service Provider Workers .

ARTICLE 32. COMMUNICATIONS

Service Provider will coordinate all media responses related to the Project with Owners, which must be approved in writing and aligned with Owners' Nuclear Development Communications. To the extent reasonably practicable, Owners will coordinate press releases related to the Project with Service Provider. No right is granted to Owners to use as a trademark the name "Westinghouse", the "Circle W" logo or the phrase "You Can Be Sure…", either alone or in combination with any other word or symbol, without the written approval of Service Provider.

ARTICLE 33. MISCELLANEOUS

33.1 Severability. In the event that any of the provisions of this Agreement are held to be unenforceable or invalid by any court of competent jurisdiction, Owners and Ser vice Provider shall negotiate in good faith to reach an equitable adjustment in the provisions of this Agreement with a view toward effecting the purpose of this Agreement, and the validity and enforceability of the remaining provisions shall not be affected thereby.

33.2 Survival. All terms that by their nature and context extend beyond the expiration or termination of this Agreement shall survive its termination.

33.3 Waiver of Breach. The waiver by either Party of a breach of any provision of this Agreement shall not be construed as a waiver of any subsequent breach by the other Party.

33.4 Entire Agreement. The Parties hereto enter into this Agreement intending to be legally bound hereby. This Agreement represents the entire agreement between the Parties with respect to and supersedes all prior agreements regarding the subject matter hereof, including the Existing Services Agreement.

33.5 Further Assurances. Each Party hereto shall, at the other Party's reasonable request, do, execute, acknowledge and deliver all such further acts, conveyances, assignments, transfers, documents and other assurances necessary to effectuate the purposes and carry out the terms and intent of this Agreement.

(Signatures on following page)

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed and attested by their duly authorized officers as of the day and year first herein above written.

GEORGIA POWER COMPANY, FOR ITSELF AND AS AGENT FOR OGLETHORPE POWER CORPORATION (AN ELECTRIC MEMBERSHIP CORPORATION), MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA, MEAG POWER SPVJ, LLC, MEAG POWER SPVM, LLC, MEAG POWER SPVP, LLC, AND THE CITY OF DALTON, GEORGIA, ACTING BY AND THROUGH ITS BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS

BY: /s/Chris Cummiskey

NAME: Chris Cummiskey
(Typed or Printed)

TITLE: Executive Vice President, Georgia Power Company

WECTEC GLOBAL PROJECT SERVICES INC.

BY: /s/David C. Durham
NAME: David C. Durham
(Typed or Printed)
TITLE: President

WESTINGHOUSE ELECTRIC COMPANY LLC

BY: /s/Jose E. Gutierrez

NAME: Jose E. Gutierrez
(Typed or Printed)

TITLE: President and CEO

EXHIBIT A
SERVICES AND DIVISION OF RESPONSIBILITY

Table A.1 – Scope of Services

	Service Provider Scope	Notes
ENGINEERING SERVICES		
E1	Records management/document delivery for the Design Engineering	Will facilitate reconciliation of simulator modeling to Unit 3 configuration.
E2	Maintain design authority responsibility	Includes delegated ASME B&PV responsibility. Includes engineering support associated with design changes. Design changes will be authorized by SNC.(per Agreement, section 5.7(a))
E3	Support engineering management and design services to complete the AP1000 ® standard plant portion of the Vogtle Units 3 and 4 design	Includes Site and field and offsite engineering.
E4	Support engineering management and design services to complete the Vogtle Units 3 & 4 Site-specific design	Includes Site and field and offsite engineering.
E5	Engineering support for completion of security-related SSCs	Includes Building 304, Building 305, and Receiving Warehouse structures and equipment. Includes related procurement support. Includes support of system interfaces with Vogtle 1&2 security-related SSCs.
E6	Engineering support for security perimeter	Includes transitional boundary between Unit 3 and Unit 4. Includes related procurement support, computer system installation and testing, and security system ITAAC closure.
E7	Engineering support for civil work	Includes “No Man’s Land” between Unit 3 and Units 1&2. Includes related procurement support.
E8	Engineering support for site communications systems; security computer system; and alarm stations	Includes integration of Units 1&2 security and communications systems. Includes related procurement support.

	Service Provider Scope	Notes
E9	Full implementation of Fuel Load Baseline (including Baseline 8 and post-Baseline 8) at the Site and Cranberry	Includes, but is not limited to, software development, testing, and installation; Baseline 8 simulator; Baseline 8 procedures; Integrated System Validation (ISV) and Human Factors Engineering (HFE) activities including final resolution of BL7 ISV, TSV and DV HED's, classroom training development and delivery to the ISV subjects, ISV shakedown, development of APP-OCS-GER-420 and 520 reports to support ITAAC closure; and I&C hardware and software implementation. In connection with I&C hardware and software implementation, Service Provider to support SNC's procurement of spare parts based on lessons learned from other nuclear construction projects.
E10	Cyber security support, including support for ongoing CDA assessment, remediation, and validation scope	Includes providing documentation/procedures, design information, databases/tools and supporting updates to the same. Includes upgrade of core I&C systems for compliance with cyber security requirements.
E11	Complete CYS design, testing, and implementation	Includes software development, testing, and installation.
E12	Support for NRC core I&C inspections and cyber security program development	Support includes participation in NRC inspections and ITAACS for I&C systems, software and documentation utilized for recommending vendor upgrades to procured equipment and SNC Site cyber program development.
E13	Maintain Westinghouse ASME Program and N Stamp	Includes maintenance of ASME QA program(s).
E14	Safety analysis support for startup	Emergent safety analysis, transient, etc. support necessitated by changes to flows, temperatures, detectors, etc. Must ensure engineering changes do not affect safety analysis.
E15	Certified for Construction drawings	Service Provider will provide support for the development of "as-built" drawing.
CONSTRUCTION SUPPORT SERVICES		
C1	Resident Engineer (with design authority approval capacity) located at the Site	Resident engineer will be an onsite engineer with the authority to sign-off on design change to the site specific design as well as the standard plant design
C2	Provide staffing, facilities, documentation, and program management platforms/programs to support ongoing implementation of construction security, FFD, and access and screening functions	--
C3	Maintain ASME programs	These programs include WEC ASME QA programs as required to comply with ASME code requirements.

	Service Provider Scope	Notes
C4	Gathering and distributing to SNC lessons learned from China AP1000 ® projects, especially those lessons learned related to construction, testing, and startup activities.	
C5	Provide schedule information and performance monitoring support services	Provide access to the live Primavera P6 Integrated Project Schedule for the Project until such time that the schedule can be migrated to a SNC domain; this access includes schedule(s) or schedule information that may reside within the VC Summer Primavera environment, if those schedule(s) or schedule information are applicable to the Project. Provide staffing to support the SNC-led Project Controls department performance monitoring and usage of the Primavera P6 Integrated Project Schedule through the transition period. Maintain licenses and applications, including Primavera P6, Deltek Acumen Fuse, SmartPlant, and Maximo software.
C6	Support of generation and revision control of the Construction Records Information Management (RIM) work packages	Review and closure of RIM packages to site data center (SDC). Support for transfer of documents from SDC to SNC document management system (CIMS, Documentum). Support coordination of RIM work packages (records) into SNC document management system and long term goal of usage of a single Site repository for document control.

	Service Provider Scope	Notes
C7	Maintain and support IT solutions and IT infrastructure required to complete the Project, including the onsite IT team for support of the Site IT network and associated infrastructure	Charlotte, Canton, Cranberry and on-Site IT teams to provide full support for all construction and engineering support applications, network engineering, telephony and functional user support for the Project. Includes provision and maintenance of WECTEC/Westinghouse databases and software including base software, application software, Third Party software, configuration data, software documentation; lifecycle maintenance and required upgrades; provision and management of all hardware and associated maintenance. Includes maintaining the following such that applications and data are recoverable: source code for applications, archived vendor software installations along with configurations / customizations, archived data for applications, installation documentation for applications, installation documentation for any supporting applications, and application architecture diagrams. Includes third party escrow of critical applications and data (example: Iron Mountain) in order to provide SNC Technology Solutions a means to recover applications and data should they become unavailable through WECTEC. Includes support of all on-Site WECTEC IT infrastructure including network (wired and wireless), cameras, PC's, switches, firewalls, telephony, and any other IT equipment. Includes provision and maintenance of network hardware and associated software configuration data, software/hardware documentation, lifecycle maintenance, and required upgrades. Includes leaving all existing WECTEC Vogtle WAN/LAN infrastructure (Ethernet / Fiber) in place when Service Provider ceases to provide Services, regardless of the reason for Service Provider ceasing to provide Services.
C8	Provide the staffing support to complement SNC staffing for conducting the daily business of the OCC on a 24/7 basis	Operational Control Center (OCC) support will include facilitating and tracking issues, maintaining status and reporting critical activities as well as support for coordination of engineering, procurement, construction and startup and facilitating strategic planning for milestones to ensure performance consistent with the Post-Transition Schedule. Staffing support includes coordinators, supervision admins, procurement, FE's, DE's, QC, schedulers, and data analysts.

	Service Provider Scope	Notes
C9	Support for compliance with all environmental permit and regulatory obligations for Vogtle Units 3 and 4 (including Site facilities)	Includes provision of all required labor, equipment and consumable supplies. Includes coordinating with construction organizations (Safety, Area Managers, Subcontractors, etc.); regulatory required inspections; performing required environmental observations, data collection, and sampling; waste management (Hazardous, Universal, Oil Debris, etc.); SPCC containment management; Spill Response/Spill Kit Management; and implementing construction storm water Erosion Sediment & Pollution Prevention Plans (Storm Water Maintenance). Includes SNC access to existing WECTEC Storm Water Design Professionals.
C10	Provide the staffing support necessary to complement SNC staffing for scoping and building work packages, work package tracking, and work package closure	Includes oversight of involved subcontractors. Staffing support includes planners, procurement, FE's, DE's, QC, etc.
C11	Support of chemistry testing for testing and startup	
C12	Oversight and Control of ASME Welding Processes	ASME welding – N-stamp certificate holder requirement
LICENSING SERVICES		
L1	ITAAC Support	Includes ITAAC schedule activity management; subcontract scope review, support work package screening; vendor/supplier prioritization; Principle Closure Documentation (PCD) development; Completion Package (CP) development; PDP (Performance and Documentation Plan) development; and PCD tracking and maintenance. Includes design, installation, analyses and testing information required to support ITAAC closure.

	Service Provider Scope	Notes
L2	Preparation of Licensing Change Packages and departures (LAR and non-LAR)	Includes markups to the current Licensing Basis (e.g., UFSAR, Tier 1, Technical Specifications, etc.), results of screening activities, and Licensing Impact Reviews for engineering products. Support NRC meetings for LARs and responses to NRC Requests for Additional Information at Owners' request. Includes risk release reviews upon request by Owners. Service Provider shall ensure all engineering support (including arising out of Baselines, ITAAC, or construction support) related to licensing materials (either covered with the Services or licensing materials being prepared by Owners) is completed such that the licensing materials can be developed in compliance with the Post-Transition Schedule. Support SNC and other owners before state/federal regulatory authorities. Maintenance of LCP schedule ties, licensing construction holds, schedule and program management.
L3	Licensing support of emergent engineering issues	Owners may request input for development of licensing positions or development of DCPs. Includes participation in LRBs, CCBs, Operations Safety Committee, Offsite Operations Safety Committee and preparation/support of emergent tech spec changes.
L4	Support for NRC inspections, requests for information and Owner RFIs	
L5	Support for any challenges, hearings, or proceedings before the NRC, including, but not limited to, related to license amendments and ITAAC closure	Support includes NRC inspections, topical report reviews that directly support the Vogtle project, industry and site Quality Assurance audits, and INPO assessments through plant construction and testing.
L6	Support 10 CFR Part 21, 10 CFR 50.55(e) and 10 CFR 50.46 evaluations and reports	Including continuing to report 10 CFR Part 21 and 50.55(e) issues and 10 CFR 50.46 evaluations in accordance with regulations.
PROCUREMENT SERVICES		
P1	Procurement of Modules • Mechanical Modules • Structural Modules, including Book II and III Materials • Safety related structural steel platforms and structures	• Management of all direct procurement and support organizations, including: o Engineering (procurement and design) o Supply chain/commercial/legal o Licensing o Quality

	Service Provider Scope	Notes
P2	Procurement of Engineered Components (includes ASME valves) • Tagged mechanical and electrical equipment (ex., valves, pumps, tanks, heat exchangers, MCC, batteries, etc.) • Standalone power source for security systems in the standard plant design • Security system computer equipment and associated infrastructure for all plant buildings	o Project controls o Management of assigned budgets and/or input into the SNC financial governance process o Document Management • Interface with design authority o Cyber security modifications o Design changes/improvements and lessons learned o Disposition of vendor requests for changes and non-conformances • Commercial grade dedication as required • Incorporating design changes into Permanent Plant Equipment only, post-delivery • Management of all quality/potential quality issues (regardless of when identified) • Maintain requisitioning, purchasing and vendor interface for engineering, procurement and any software purchases and licenses • Transition specific software platform responsibility to SNC, as requested Radiation monitoring equipment is supplied as part of the I&C package. Neutron sources are supplied under the fuels contract.
P3	Procurement of ASME III Materials (Pipe/Pipe Supports and other ASME procurements)	
P4	Procurement of Highly Engineered Materials (Rebar, Embeds, non-ASME Pipe/Pipe Supports)	
P5	Procurement/management of consumables, spare parts, components, instrumentation, equipment, and outside services related to testing and startup	Includes support for development of spare parts lists to support startup testing and plant operation. Includes management of all non-safety issues.
P6	Maintain and continue execution of Westinghouse Human Factors Program with existing personnel	Plant equipment local control panels shall conform to human factors guidelines as described in APP-GW-GRP-001.
PROGRAM SERVICES		
ONP1	QA/QC	In accordance with 10 C.F.R. Part 50, Appendix B and ASME 1-1994. See Agreement, Article 13
ONP2	Continue execution of Site ECP Program with existing personnel	Includes provision of requested information to SNC ECP leadership.

	Service Provider Scope	Notes
ONP3	Maintain and manage Westinghouse QA program, including maintaining Westinghouse CAPAL program.	The Corrective Action Program is required to be compliant with 10 CFR Part 50 Appendix B for safety related SSCs. Includes performance of Root Cause Analyses, Apparent Cause Analyses, and preparation of related supporting documentation (CAPAL attachments related to the Services)
ONP4	Implementation the Interface of Corrective Action Programs (ICAP) Agreement and supporting full implementation of SNC CAP process.	Support transition to a single PI & CAP for the Site and development and implementation of interface protocol between Service Provider's Corrective Action Program and SNC's PI & CAP.
ONP5	Nuclear Safety Culture (NSC) Program	
ONP6	Fully implement a Lessons Learned Program for Vogtle Units 3 and 4	
ONP7	Fully implement a Trending Program in accordance with corrective action programs	
ONP8	Aging Management for Electrical Cables	SNC will support Service Provider in completion of TAN DELTA testing.
ONP9	Equipment Qualification	
ONP10	Containment Leak Rate Testing	
ONP11	MOV/AOV	
ONP12	PSI/ISI & PST/IST	
ONP13	Snubber programs	
ONP14	Development, implementation, and maintenance of fire protection program for areas under Westinghouse control.	Includes compliance with SNC fire protection program for areas under SNC control.
ONP15	Flow Accelerated Corrosion Acceptance Criteria	
ONP16	Construction Training	Support initial and requalification needs for the Site construction; review and oversight of qualification program and maintenance of programs; and provide for LMS entry, qualification structure, and content changes.
ONP17	Emergency Preparedness and Training	
ONP18	QA letter responses	Related to the communication of Site D/Ns and/or supplier issues that are identified during audits and resolution of those items.
ONP19	Construction Procedure Maintenance	Service Provider to support for ASME procedures
ONP20	Welding Program	Service Provider to support for ASME procedures
ONP21	Project Management Functions	
ONP22	Baseline Test Data Accumulation and Analysis	

CONFIDENTIAL& PROPRIETARY
CONFIDENTIAL TRADE SECRET INFORMATION

	Service Provider Scope	Notes
ONP23	FOAK test programs	Include equipment
ONP24	Procurement / subcontract support	
ONP25	Equipment labeling	Support
ONP26	Overall equipment maintenance program	Support
OPS READINESS SERVICES		
OP1	Training	Support initial and requalification needs for the Site construction; review and oversight of qualification program and maintenance of programs; and provide for LMS entry, qualification structure, and content changes.
OP2	Support of physical security program implementation, including delivery of design information	Including work required to support fuel on-Site
OP3	Support of Initial Test Program (ITP) (includes Component, Pre-Operational, and Startup Testing) Performance Testing, and engineering support	Westinghouse will support SNC for site acceptance testing.
OP4	Development of testing specifications and procedures, preparation of SSCs for testing, conduct of testing and supporting programs/processes	Includes evaluation of test results, and resolution of RFIs, design issues, testing deficiencies, or other issues identified during testing. Development of test acceptance criteria and support approval.
OP5	Procedure preparation and updating for areas related to engineering support	Includes the drafting, updating, correction, and maintenance of all required procedures. Includes all standard plant procedures, except where directed otherwise by Owners.
OP6	Maintain and upgrade Unit 3 referenced simulators to successfully achieve Plant Referenced configuration including documentation and software changes necessary to implement baseline 8 design changes deferred to a later date.	Include all updated Simulator Training System (STS) documents

	Service Provider Scope	Notes
OP7	Provide procedures in time to support operator and instructor GAP Training as per the SNC schedule (Update to BL 8.4 or greater)	Includes: i. Deliver remaining SOPs ii. Deliver remaining MTIS procedures iii. Deliver remaining FHS procedures iv. Deliver AOPs and associated background documents v. Deliver EOPs and associated background documents vi. Deliver GOPs vii. Deliver P72 procedures viii. Deliver SAMGs including FLEX and Fukushima regulatory-required updates ix. Deliver ARPs x. Deliver site specific procedures as identified by SNC xi. Perform simulator validation of EOPs and AOPs Includes set-point data base to maintain ARPs in sync with procedures listed in i – viii above.
OP8	M&TE (Maintenance and Test Equipment)	
OP9	Configuration management	

Notes:

1. Where the term “includes” or “including” or similar is used, it should be read to mean “includes, but is not limited to” or “including, but not limited to”.

2. As provided in the Agreement, SNC may elect to transition certain Services or portions or Services from Service Provider to SNC or to a Third Party. Nothing in this Table A.1 limits SNC’s right to so elect, and Service Provider agrees to provide support for any such transition elected by SNC in accordance with the Agreement.

3. For all program-related Services, SNC anticipates transition of responsibility for and management of all programs to SNC either during the term of the Agreement or as part of the winding down of Services under the Agreement. For program-related Services, the Scope of Services listed in this Table A.1 should be presumed to include Service Provider’s support for any such transition and continued support as directed by SNC after such transition.

Table A.2 – Division of Responsibilities

Facilities and Functional Areas	Division of Responsibility
Asset Preservation to Maintenance	SNC with Service Provider support
Construction Engineering	SNC with Service Provider support*
Licensing	SNC with Service Provider support
ITAAC	SNC with Service Provider support*
Information Technology	SNC with Service Provider support
Construction	SNC with Service Provider support*
Procurement	SNC with Service Provider support
ITP	SNC with Service Provider support
PI & CAP	SNC with Service Provider support
Document Control	SNC with Service Provider support
Cyber Security	SNC with Service Provider support
Training	SNC with Service Provider support
Digital I&C, Baseline 8, Simulator (LSS/CAS/PRS), I&C support through ITP	Service Provider (subject to Owners' approval of changes)
Fire Protection	SNC with Service Provider support
Operational Control Center	SNC with Service Provider support*
Plant Security and Communications	SNC with Service Provider support
Vogtle 3 & 4 Plant Design Authority and Vogtle 3 & 4 Plant Design	Service Provider (subject to Owners' approval of changes)
Work Management	SNC with Service Provider support
Aging Management for Elec Cables	Service Provider
Equipment Qualification Program	SNC with Service Provider support
Containment Leak Rate Program	SNC with Service Provider support
MOV and AOV Program	SNC with Service Provider support
ISI Program	SNC with Service Provider support
PST/IST Program	SNC with Service Provider support
Snubber Program	SNC with Service Provider support
Project Controls and Project Management	SNC with Service Provider support*

*The Parties acknowledge that Service Provider's support under the noted areas shall be limited to staff augmentation unless mutually agreed otherwise.

EXHIBIT B
DELIVERABLES

The list of the types of Facility documentation to be provided to Owners will include the types of deliverable documents as provided in the table below. If appropriate and requested by the Owners, where there is a difference between the as-designed and as-built condition of the Facility, applicable Facility documentation shall reflect the as-built condition of the Facility. Each document shall be provided with all outstanding Non Conformances and EDCRs, as well as any outstanding configuration management system debt at time of turnover.

AP1000 ® Facility documentation classified as Proprietary Class 2 or Non-Proprietary Class 3 specifically related to the design, construction, operation and maintenance of the Facility and identified in the table and lists below shall be provided via a controlled website or similar electronic information portal (but not SharePoint).

Instructions for access and review of Facility documentation, including a listing of index fields and query options, shall be provided by the Service Provider and may be electronically posted via a controlled website or similar electronic information portal that allows Owners to download such documentation (but in no event shall Service Provider use SharePoint for this purpose). All controlled Facility documentation will be provided with revision level control, and be uniquely designated.

The proprietary or non-proprietary classification of all documents included in the Facility documentation will be defined on an individual document level. Classification shall be in accordance with Service Provider's BMS-LGL-28, "Proprietary Information and Intellectual Property Management Policies and Procedures". Owners' treatment of Facility documentation is described in Article 14 of the Amended and Restated Services Agreement.

I. Categories of Deliverables:

A. <u>Documentation</u>

See detailed breakdown table below in Section D.

B. <u>Equipment</u>

As part of its provision of the Services, Service Provider will deliver certain equipment, hardware and associated software, machinery, components, materials, and other items that will become a permanent part of the Facility (including certain items provided by Third Parties) ("Equipment"). During the Transition Period, the Parties will develop a schedule for the provision of the Equipment to support the Project Schedule.

This section does not list all Equipment or all categories of Equipment that will be delivered by Service Provider in connection with the Services. Service Provider will provide such Equipment as part and parcel of its performance of the Services. However, for the avoidance of doubt, the following Equipment will be provided pursuant to this Amended and Restated Services Agreement (all items include related components, hardware, and software, as applicable):

1. Limited-scope and plant reference simulators updated to Baseline 8+.
2. CYS/CMS - Cyber Monitoring System
3. SES - Security computer system (ARINC)
4. Safety and non-safety I&C deliverables, including but not limited to:
   - Application software logic diagrams
   - I/O database with all I/O points
   - Termination Lists/Drawings
   - Software requirements traceability matrices
   - Operation and Maintenance Manual (O&M Manual)
   - Hardware change kits and FCN documentation
   - Hardware installation instructions
   - Ovation and Common Q Logic and graphics packages
   - Instrumentation datasheets, specifications, and installation details
   - Regression testing reports and analysis
   - System design criteria and functional specification
5. Standard Input-Output System (SIOS) test cart for PMS testing
6. All safety and non-safety core I&C systems
7. Permanent Plant Equipment
8. Modules
9. Engineered Material (Rebar, Embeds, Piping and Pipe Supports)
10. ASME Material

C. <u>Software/Databases</u>

1. Baseline 8 (fully implemented for all applicable systems/functions)
   - all software updates and any future I&C design changes
2. NAP Monitor and Developer software tool
3. Executable Software for I&C systems
4. PLCs and any component software that interfaces with PLCs
5. RITS data access
6. Computerized Procedure System, including procedure builder executable software
7. Wall Panel Navigation executable software
8. DCIS application executable software

9. Provide base software and licenses required to support installation of I&C (Common Q, Ovation, etc.)
10. All BL8 software delivery for ICE-TE

D. Documentation

GENERAL AND ADMINISTRATIVE	Document Number Notes - Comments [1]
1. Design Control Document (Licensing), including information identified as "incorporated by reference" in DCD Table 1.6-1.	• **APP-GW-GLR-700** (DCD Rev. 19) • **Applicable Documents Specified in Table 1.6-1 of the DCD/FSAR** (Documents Incorporated by Reference)
2. AP1000 ® and AP600 WCAPs and Technical Reports that Apply to the Implemented Design	• See above • **APP-FSAR-GLN-XXX** (Any Licensing Departures and Changes applicable to SNC)
3. AP1000 ® Documentation Guidelines and Document Numbering	• **APP-GW-GMP-005 Latest Rev.** (Document Numbering Procedure) • **APP-GW-GMP-006 Latest Rev.** (Component Numbering Procedure)
4. Core Reference Report for first core	• **APP-GW-GLR-156** AP1000 ® Core Reference Report
5. Security Related information (Target Sets, Safeguards and SUNSI Information)	• **APP-GW-GLR-066 (TR-94)** AP1000 ® Safeguards Report • **Other Assessments and Target Set Documents.** • **SUNSI information provided as applicable for each deliverable identified in this able**
6. Onsite and Offsite dose analysis reports	• Agreed Documents – Document numbers will be defined.
7. Vendor manuals	• **APP-xxx-VMM** (Vendor Manuals) • **APP-xxx-JED** (Instrument Vendor Catalog)
8. WEC Emergency Preparedness Plan (SV-G1-GSH-004)	• SV0-G1-GSH-004 .
9. Licensing documentation including a. Licensing Change Packages, including markups to the Current Licensing Basis (e.g.,	• **APP-FSAR-GLN-XXX** (Any Licensing Departures and Changes applicable to SNC along with checklists and forms providing supporting documentation)

[1] Documents listed in this column are intended to provide a list of deliverables necessary to satisfy the deliverable obligations. It is understood that some needs may occur in which other documents may be required to complete the deliverable obligations and the parties will negotiate these requests in good faith on a case by case basis.

UFSAR, Tier 1, Technical Specifications, etc.) b. Completed form detailing Engineering supporting documents c. All current native CAD files or other native file types that serve as the source files for figures in the UFSAR and Plant-specific Tier 1	• **Native Drawing Files** (FSAR drawing files)
PROJECT MANAGEMENT	**Project Management Procedures are various numbered documents. The listed documents that will meet those definitions will be provided.**
1. Project Execution Plan	
2. Project Specific Control Procedures	
3. Project Schedule (includes Engineering, Procurement, QA, ITP and Construction)	
4. Project Change Notices (Scope, Budget, Schedule Variances)	
5. Official Project Correspondence	
6. Monthly Progress Reports (which includes project control reports, project schedule status updates, financial status, etc.)	
7. PCC outstanding issues list	
QUALITY ASSURANCE	
1. Service Provider Quality Assurance Program	• Westinghouse QMS
2. QA Procedures produced specifically for Vogtle 3&4 Project which describe the interface with SNC	• Pursuant to the interface agreed per Section 13.1(c)
3. QA Data Packages, as relevant, including items such as:	• **APP-xxx-VQQ** (Equipment (formerly vendor) QA/QC - Inspection Document)
a. Approved Non-Conformance Reports/ Dispositions (N&Ds)	• **APP-xxx-VQQ** (Equipment (formerly vendor) QA/QC - Inspection Document)
b. Radiographic/Non-Destructive Test Data (Radiographs)	• **APP-xxx-VQQ** (Equipment (formerly vendor) QA/QC - Inspection Document) • **APP-xxx-VW** (Equipment (formerly vendor) Welding and Non-Destructive Evaluation)

c. Non-Destructive Examination Records (NDE)	• **APP-xxx-VQQ** (Equipment (formerly vendor) QA/QC - Inspection Document) • **APP-xxx-VW** (Equipment (formerly vendor) Welding and Non-Destructive Evaluation)
d. Heat Treatment Records	• **APP-xxx-VQQ** (Equipment (formerly vendor) QA/QC - Inspection Document)
e. Material Origin Certifications	• **APP-xxx-VQQ** (Equipment (formerly vendor) QA/QC - Inspection Document)
f. Field Inspection Reports	• **APP-xxx-VQQ** (Equipment (formerly vendor) QA/QC - Inspection Document)
g. Weld Data Reports	• **APP-xxx-VQQ** (Equipment (formerly vendor) QA/QC - Inspection Document)
h. Final Quality Inspection and Release Documents or Certificate of Compliance	• **APP-xxx-VQQ** (Equipment (formerly vendor) QA/QC - Inspection Document)
4. Applicable Quality Records supporting the current suppliers on the Westinghouse QSL (Qualified Supplier List) applicable to Vogtle 3 & 4 Project	• See Section 13.5 Audit reports produced under agreement by Third Party sources (example NIAC) are prohibited by agreement to be provided to the Owners.
ENGINEERING	
1. Systems	
a. Applicable Calculations & calc notes	• **APP-xxx-M3C-100** (Mech System Control Requirements) • **APP-xxx-M3C-101** (Instrumentation Requirements) • **APP-xxx-M3C-300** (Power Production Reliability) • **APP-xxx-E8C-100** (Elect System Control **Requirements**) • **APP-xxx-E8C-101** (Elect System Instrumentation Requirements) • **APP-xxx-E8C-100** (Elect System Power Production Requirements) • **APP-xxx-J7C** (Component Functional Logic and Setpoint Calculations) • Documents may also be 800100, 800101, **and** 800300
b. System Specification Documents (design criteria and functional specifications)	• **APP-xxx-M3-001** (Mechanical System Specification Documents) • **APP-xxx-E8-001** (AC Electrical System Specification Documents) • **APP-xxx-J7-001** (Instrumentation and Control Systems)

c. Piping and Instrumentation Diagram	• **APP-xxx-M6-** (Piping and Instrumentation Diagrams)
d. Piping Isometrics	• **APP-xxx-PLW** (Pipe Line Work Packages)
e. HVAC Duct and Support Drawings	• **APP-Vxx-MD** (Ductwork and Dampers) • **APP-xxxx-SH** (Hangers and Supports-Multipurpose)
f. Logic Diagrams	• **APP-J3-xxx** (I & C - Logic Diagrams, PBDs, Interlock Sheets)
g. Single Line Diagrams	• **APP-xxx-E3** (System One-Line Diagrams)
h. Three Line Diagrams	• **APP-xxx-E4** (System Three-Line Diagrams) • **APP-xxx-E5** (Combined Wiring Diagrams)
i. Wiring Diagrams	• **APP-xxx-E3** (System One-Line Diagrams) • **APP-xxx-E5** (Combined Wiring Diagrams) • **APP-xxx-ED** (480V, 380V & 227V Distribution Panels)
j. Piping Specifications	• **APP-PL02-Z0-101** (AP1000 ® Class 1 Piping and Non-Class 1 Extensions Design Specification) • **APP-PL02-Z0-102** (AP1000 ® Class 2, 3 Piping and **B31** .1 Extensions Design Specification) • **APP-GW-P1-200** (AP1000 ® Non-ASME III Piping **Design** Requirements) • **APP-PL02-Z0-007** (• • ® Specification for Shop Fabricated Piping) • **APP-PL02-Z0-008** (AP1000 ® Field Fabricated Piping and Installation ASME III, Code Class 1, 2 and 3 and ASME B31.1)
k. Pipe Support Details	• **APP-xxx(x)-PH** (Pipe Supports)
l. ASME III Design Reports	• **Piping and Pipe Hangers** : ASME Section III final As-built design reports for piping (Unit Specific Design reports, P0R documents) and piping supports unit specific design reports. • **Equipment:** Unit Specific Equipment (formerly **vendor**) Design Report (VDR documents)
m. Applicable AP1000 ® Safeguards Information (See Note 1)	See above in General Section.
n. Applicable AP1000 ® Equipment Databases (See Note 1)	• The following will be provided: SPF data, WEMMEX, PDS model information, MEL.
o. Master Equipment list	• MEL
p. Plant Specific Heat Balance	• **APP (And Unit)-MG01-VD** (Thermal Performance Heat Balance) • **APP-GS-M4C-100** (Turbine Heat Balance Diagram Calculations)

q. Applicable Set point Basis Documents	• **APP-xxx-M3C-5xx** (System Specification Calculation)
r. Radiation analysis reports	• **APP-xxxx-N5** (Radiation Zoning)
s. Licensing planning and management database	• Licensing Change Matrix
t. Ovation and Common Q Logic and graphics packages	• See Section B for I&C software delivery.
u. Instrumentation datasheets, specifications, and installation details	• **APP-xxx-J0-xxx** (I&C - Multipurpose) • **APP-xxx-J1** (I&C - Design Criteria) • **APP-xxx-J5** (I&C - Loop Diagrams/Termination Documents) • **APP-xxx-J8** (I&C - Installation Details) • **APP-xxxx-J2** (I&C - Instrument Locations) • **APP-xxx-J3** (I&C - Logic Diagrams, PBDs, Interlock sheets) • **APP-xxx-J1-100 series** (I&C - Design Criteria)
v. MOV/AOV vendor data sheets and design information	• Various, as provided by the vendor
w. Approved Design Change Packages (DCPs)	• **APP-GW-GEE-XXXX** (Design Change Proposals), applicable to SV0, SV3 or SV4.
2. Equipment	
a. Applicable Design or Equipment Specifications (See Note 1)	• **APP-xxx-Z0** (Functional Specifications) • **APP-xxx-Z0D** (Data Sheets) • **APP-xxx-Z0R** (Design Reports) • **APP-xxx-J1** (Automation Functional **Specifications**) • **APP-xxx-J4** (Application Functional Specifications) • **APP-xxx-PHP** (WECTEC Design Reports and Data Sheets)
b. Outline Drawings	• **APP-xxxx-V1** (Equipment - Outline Drawings)
c. General Assembly Drawings and Equipment location Drawings	• **APP-xxx-P3** (Equipment Locations) • **APP-xxx-P3X** (Equipment Locations) • **APP-xxx-E2** (Electrical Equipment Locations) **APP-xxxx-P2** (General Arrangements) • **APP-xxx-P5** (Mounting Supports) • **APP-xxx-CE** (Embedment Drawings) • **APP-xxx-SHX** (Support Index Documents)
d. Wiring Diagrams	• **APP-xxx-V4** (Equipment - Wiring Diagrams) • **APP-xxx-E0** (AC Electrical - Multipurpose) • **APP-xxx-E5** (AC Electrical - Schematic Drawings or Documents) • **APP-xxx-E5K** (AC Electrical - Schematic Drawings or Documents - Engineering and Field Sketches)

	• **APP-xxx-EW** (AC Electrical - Wire and Cable) • **APP-xxx-J8Y** (I&C - Installation Details - Document)
e. Control Logic Drawings	• **APP-xxx-J3** (I&C - Logic Diagrams, PBDs, Interlock sheets) • **APP-xxx-J1-100 series** (I&C - Design Criteria)
f. Electronic Equipment Software descriptions, versions and instructions	• **APP-xxxx-GHY** (Infor. Mgt Syst and Info. Technology Document)
g. Electronic Equipment Software Validation and Verification Packages	• **APP-xxxx-T2R** (Test Result Reports)
h. Equipment Qualification data packages	• **APP-xxx-VBR** (EQ Summary Reports) • **APP-xxx-VDR** (EQ Test Reports and some Design Reports) • **APP-xxx-VQQ** (Quality Release and C of C)
i. Environmental Reports (includes conclusions and summaries but not detailed test data)	• **APP-xxx-VTR** (Test Reports) • **APP-xxx-VPR** (EQ Test Reports)
j. Applicable Equipment Vendor Technical Manuals or Information Packages (See Note 1)	• **APP-xxx-VMM** (Vendor Manuals) • **APP-xxx-JED** (Instrument Vendor Catalog) • **APP-xxxx-J0M** (Technical Manual)
k. Vendor Schedules for Manufacture and Delivery of Commodities (including modules and Shield Building panels)	• Schedule information as available
l. Hardware installation instructions	Would be in Vendor Manuals or specific installation procedures for Westinghouse provided components.
m. Warranty related information (e.g., vendor warranty, warranty claims)	Would be in Vendor Manuals and provided by vendors.
n. Combustible Loading Calculations & Schedules	• **Fire Protection Analysis Report APP-xxxx-N4R** • **APP-xxxx-AF** (Fire Protection/Fire Boundaries)
3. AP1000 ® Building Drawings and Reports	
a. General Arrangement Drawings	• **APP-xxxx-P2** (General Arrangements) • **APP-xxx-E6** (Electrical Hazard maps) • **APP-xxx-E9** (General Notes) • **APP-xxx-EB** (Bus Dusts) • **APP-xxx-EG** (Grounding) • **APP-xxx-EL** (Lighting) • **APP-xxxx-AF** (Fire Protection/Fire Boundaries)
b. Concrete Outline Drawings	• **APP-xxxx-CC(x)** (Concrete)

c. Rebar Drawings	• **APP-xxxx-CR** (Concrete reinforcement) • **APP-xxxx-C3** (Key Concrete Reinforcement) • **APP-xxxx-C8** (Concrete Reinforcement Placing & Fabrication Drawings)
d. Seismic Analysis Reports (results, not input calculation notes or models)	• **APP-xxxx-VGR** (Equipment (formerly vendor) Seismic Report) • **APP-xxxx-VDR** (Equipment (formerly vendor) Design Report)
e. Containment Penetration Drawings	• **APP-xxxx-P0** (Piping Multipurpose-Penetrations) • **APP-xxxx-P0X** (Piping Multipurpose-Penetrations List) • **APP-xxxx-M0** (Mechanical Multipurpose-HVAC Duct Penetrations) • **APP-xxxx-M0X** (Mechanical Multipurpose-HVAC Duct Penetrations List) • **APP-ML05-V2-xx(x)** (Platework, Liners, and Penetration Sleeves) • **APP-MV50-V1-xxx** (Equipment - Outline Drawings) • **APP-MV50-V2-xxx** (Equipment - Assembly Drawings) • **APP-xxxx-E0** (Electrical Multipurpose-Penetrations) • **APP-xxxx-E0X** (Electrical Multipurpose-Penetrations List) • **APP-xxxx-V1** (Mechanical Multipurpose - Structure, Components Penetrations) • **APP-xxxx-V6** (Mechanical Multipurpose - Structure, Components Penetrations) • **APP-EY01** (AC Electrical Specialties, Penetrations) • **APP-EY02** (AC Electrical S p ecialties, Penetrations)
f. Wall and Floor Penetration seal details and supporting test reports	• See above Penetration Details
g. Embedment and Attachment Drawings	• **APP-xxxx-CE(x**) (Concrete Embedded Metal)
h. Raceway and Raceway Support Drawings	• **APP-xxxx-ER** (Raceway (AC or DC)) • **APP-xxxx-ERB** (Raceway (AC or DC) BOM) • **APP-xxxx-SH** (Hangers and Supports-Multipurpose) • **APP-xxxx-SH-Exxx** (Hangers and Supports-Multipurpose) • **APP-xxxx-S7** (Raceway/Duct/Instr. Location Drawings)

i. Cable and Conduit Lists including routing data (cable database)	• **APP-xxx-E0X** (AC Electrical Multipurpose List) • **APP-xxxx-ERR-500 Series** (Raceway AC or DC **Report**) • **APP-xxx-EW** (AC Electrical - Wire and Cable) • **APP-xxxx-E0** (AC Electrical-Multipurpose) • **APP-AB01-xxxx** (Architectural Blockouts and Barriers) • **Database output from Cable Manager**
j. Cable Termination Details	• **APP-xxx-EW** (AC Electrical - Wire and Cable) • **APP-xxx-E3** (AC Electrical - Single Line Diagrams) • **APP-xxx-E5** (AC Electrical - Schematic Drawings or Documents) • **APP-xxx-E9** (AC Electrical - Notes, Symbols and Details) • **APP-xxx-J5** (I&C - Loop Diagrams/Termination Documents) • **APP-xxx-DDY** (DC Distribution Panels Documents) • **APP-xxx-EAY** (Low Voltage Distribution Panel Documents)
k. Structural Steel Frame Drawings	• **APP-xxxx-SS(x)** (Structural Steel)
l. Structural Modules Sub-Assembly Drawings	• **APP-xx(x)-S5(x)** (Structural Sub-Module Documents) • **APP-xx(x)-S4(x)** (Structural Sub-Assembly Documents) • **APP-xx(x)-S8(x)** (Structural Installations Documents)
m. Composite lay-out drawings	• **APP-JC01-V1** (Equipment (formerly vendor) Outline drawing)
n. Module Drawings	• See above item m.
o. Instrument Tubing and Support Drawings	• **APP-xxx-JTW** (Instrument and Tubing Pipes Work Packages)
p. Plant 3D PDS Model files including WEMMEX	3D model is not a 'quality record', but is a provided as a quality tool to assist in plant management and operations. "As-Designed for Standard Plant". Only applicable to Standard Plant Buildings – including WEMMEX data and attributes. Method of delivery and access throughout project to be defined jointly with Owner

q. Civil Drawings and Lists (e.g. joint sealers, roofing, building sealers. doors and frames, stairs, room finish, ceilings, elevators, masonry, membranes/barriers, embedments, blockouts, etc.)	• **APP-xxxx-AG** (Architectural - General) • **APP-xxxx-AM** (Architectural - Masonry) • **APP-xxxx-AR** (Architectural- Rooms and Room Numbering) • **APP-xxxx-AT** (Architectural - Thermal/Moisture) • **APP-xxxx-AW** (Architectural - Woods, Plastics, Gypsum, Composites) • **APP-xxxx-A0** (Architectural - Multipurpose) • **APP-xxxx-A9** (Architectural - Notes, Symbols, and Details) • **APP-xxxx-AB** (Architectural - Blockouts and Barriers) • **APP-xxxx-AD** (Architectural - Doors, Hatches, and Windows)
r. Building Drawings and Schedules (floors, roofs, walls, elevations, framing, columns, base plates, cranes/hoists, stairs, platforms, equipment support, etc.)	• **see above** • **APP-xxxx-AR** (Rooms and Room Numbering)
4. Configuration management metadata including Design Debt from SmartPlant Foundation and Documentum	Metadata and document attributes in Documentum, EDMS documentum, and SmartPlant Foundation for SV0, SV3, and SV4.
5. Cyber Security Identification, Assessments and Remediation	• **APP-GW-Y5R-001** (Identification Report) • **APP-xxx-Y6R-001** (Assessments reports) • **APP-GW-Y8** (Cyber Security - Specifications) • **APP-GW-Y4** (Cyber Security - Drawings/Diagrams)
6. China Lessons Learned for AP1000 ®	• Not a document or database.
7. DCP database (information in Smart Plant Foundation)	• Metadata in SPF on DCPs.
8. Applicable E&DCRs	• **XXX-XXX-GEF** (E&DCRs applicable to SV0, SV3, and SV4)
9. Safety analyses reports (e.g., LOCA analysis	• Reports - does not include calculations or methodologies as described in the initial note.
PROCUREMENT	**Procurement Documents are various numbered documents. The documents that will meet those definitions will be provided.**
1. List of suppliers from the Westinghouse Qualified Suppliers List (QSL) and WECTEC (QRL)	The suppliers on these lists are limited to safety-related suppliers providing items or services to the Vogtle 3&4 project (see Section 13.5)

2. Source Verification, Supplier Audits & Reports	Pursuant to Section 13.5
3. Site Receipt Inspection Procedures	
4. Handling, Shipping, and Storage Procedures	
5. Equipment Technical Specifications and related drawings	
6. Vendor Contracts	
7. Vendor Documentation, Records, Reports, etc. as provided to Westinghouse by vendor	
CONSTRUCTION	**Documents are various numbered documents. The listed documents that will meet those definitions will be provided.**
1. Construction Execution Plan	
2. Site Plan	• **APP-xxxx-X4** (Surveys) • **APP-xxxx-X2** (Site Plans & Prospective) • **XXX-xxxx-X9** (General Notes) • **XXX-xxxx-XD** (Site Drainage) • **XXX-xxxx-XE** (Excavation) • **XXX-xxxx-XF** (Fencing) • **XXX-xxxx-XR** (Rail) • **XXX-xxxx-XS** (Roads) • **XXX-xxxx-XP** (Site drawings) • **XXX-xxxx-XG** (Site grading drawings) • **XXX-xxxx-PL** (Pipe Line Underground) • **XXX-xxxx-XP** (Site Pilings and Caissons)
3. Construction Specifications	
4. Applicable Construction Drawings (See Note 1)	
5. Safety Reports	
6. Safety Data Sheet	
7. Field Purchase Orders, Receipt & Audit Reports for permanent plant equipment	
8. Field Deficiency Reports	
9. Welding Records (PQR, PQAR and WPS)	
10. Field Engineering Procedures	
11. System Flushing Index & Reports	
12. Construction Testing Reports (included in Turnover Packages)	
13. Work packages including all phases of work	

14. Equipment / System / Area Turnover Packages	
15. Construction Lifting, Handling & Erection Procedures	
16. Construction procedures (Fluor)	
17. Batch Plant Procedures	
18. Construction Test and Inspection Records	
19. Heavy Equipment Records (Operating procedures, inspection records, etc.)	
20. Boundary Identification Packages	
21. Lifting plans (e.g., CA01 lift plan)	
22. Heavy Lift Derrick Removal Plan	
23. Safe Load Plans and Supporting Calculations	
24. Civil Material & Property Reports	
25. Mechanical Property Records for Safety Related Components	
26. PM records (warehouse and installed pms)	
27. Mechanical, Civil, Electrical and I&C Installation and Inspection Procedures	
28. Occupancy Inspections & Reports	
29. Measuring and Test Equipment program documents and data	
30. Records to support environmental reporting	
31. Construction training materials	
32. Well water use records/logs (MU3 & MU4 and the Dewatering system)	
33. Construction Storm water Erosion, Sedimentation & Pollution Control(ES&PC) Plans for all NOI areas.	
TESTING & STARTUP	
1. AP1000 ® Standard Startup Site Administrative Manual	• **SV0-GW-GBH-360** (Site Specific Commissioning Program) • **APP-GW-TSM-3XX** (Startup Administration Manual) • **APP-GW-GJP-150** (Operating Procedures Verification And Validation) • **APP-GW-GJP-152** (Operation Procedure Development, Verification And Approval Process)

	• **APP-GW-GJP-100** (Writer's Guideline For Operating Procedures) • **APP-GW-TSP-105** (Preparation of AP1000 ® Startup & Operations Support Test Procedures and Specifications)
2. AP1000 ® Standard Pre Operational Testing Specifications and Procedures	• **APP-XXX-T1-5XX** (Test Specifications) • **APP-XXX-T1P-5XX** (Test Procedures) • **APP-XXX-T1D-XXX** (Testing Data Sheets) • **APP-XXX-T1R0-XXX** (Testing Requirements/Reports)
3. AP1000 ® Standard Structural Integrity Test Procedure	• **APP -MV50-T1** (CV Structural Integrity Test Specification)
4. AP1000 ® Standard Integrated Leak Rate Test Procedure	• **APP-CNS-GJP-801** (Type A - Integrated Leak Rate Testing Procedure)
5. AP1000 ® Standard Testing & Maintenance Procedures (Initial Start-up and Operations)	• **APP -xxxx-T1P** (Testing Procedures) • **APP -xxxx-GJP** (General Operation Procedures) • **APP-XXX-T1-6XX** (Startup Test Specifications) • **APP-XXX-T1P-6XX** (Startup Test Procedures) • **APP-XXX-T1-65X** (Test Specifications) • **APP-XXX-T1P-65X** (Test Procedures)
6. AP1000 ® Standard Testing Acceptance Criteria (ITAAC) Closure Packages	• **APP-XXX-ITH** (ITAAC closure Plans) • **ITAAC Database information** • **ITAAC Principle Closure Documents** that are considered deliverables discussed in other parts of this table
7. AP1000 ® Standard Operating Procedures (e.g. Normal, Emergency)	• **APP-GW-GJP-1XX** (General Operation Procedures) • **APP-GW-GJR-1XX** (General Operation Peports) • **APP-GW-GJP -2XX** (Emergency Operation Procedures) • **APP-GW-GJR-2XX** (Emergency Operation Background) • **APP-GW-GJP -3XX** (Abnormal Operation Procedures) • **App-GW-GJR-3XX** (Abnormal Operation Background) • **APP-XXX-GJP-40X** (Alarm Response Procedures) • **APP-XXX-GJP-10X** (System Operating Procedures)) • **APP-XXX-GJP-8XX** (Maintenance, Test, Inspection, & Surveillance Procedures)
8. Spare Parts Lists	• Not defined yet but will provide

9. Special Tools Lists	• Not defined yet but will provide
10. Calibration Procedures	• **APP-xxxx-GJP** (General Operation Procedures)
11. Measuring and Test Equipment program documents and data	• Not defined yet but will provide
12. Calibration, Startup and Performance Test Reports (including Calibration records)	• **APP-xxxx-T1R** (Testing Requirements/Reports)
13. Factory Acceptance Test reports	• **Vendor Manuals** • **APP-xxx-T2R** (Testing Report)
14. Chemistry Specifications and Requirements	• **APP-GW-GEM-200** Chemistry Manual • **APP-XXX-Z0** (Specifications) • **APP-GW-Z0-604** (Coatings for CV) • **APP-G1-X0-001** (Coatings Design Requirements)
15. Digital Test Strategy	• Document to be identified later.
16. Component Test Packages	• Would be in Work Packages or Construction documents.
17. [RESERVED]	[RESERVED]
18. Operator GAP Training Materials	• Document to be identified later.
19. Punch Lists	• Document to be identified later.
20. Special test instrumentation specs/requirements; data acquisition systems?	• Document to be identified later.
OTHER	**Documents are various numbered documents. The listed documents that will meet those definitions will be provided.**
1. Project-specific CAP/ICAP records when closed	Pursuant to the interface agreed per 4.1(g)
2. Simulator	Delivered
a. Design – simulator drawing package and model requirements documents	
b. V&V records – simulator test reports	
3. Physical security (SES)	See General Section Item 5.
a. Procurement documents	
b. Design documents, reports	
4. Aircraft Impact Assessment Reports	Document to be identified later.
5. Cyber Security Project Governing Documents	See Engineering Section Item 5.
a. Identification and Assessment Data	
7. Human Factors Engineering (HFE) Plans and Reports	• **APP-OCS-GEH** (Human Factors - General

	Engineering Plan) • **APP-OCS-GER** (Human Factors - General Engineering Report)

Note 1: "Applicable" being defined as that documentation for which the BMS-LGL-28, "Proprietary Information and Intellectual Property Management Policies and Procedures", evaluation process permits delivery to Owners. Documents types that are not categorized as deliverable documents include models (computer, engineering and evaluation models), methods, inputs to methods, developmental or manufacturing test data, experience-based data, correlations and sensitivity studies.

EXHIBIT C
RATES AND INVOICING

RATES AND REIMBURSABLE COSTS

1. "Fee" shall mean the total of the amounts paid under Sections 3(e), 6, 7 and 13.
2. This Agreement is a fully cost-reimbursable contract that covers the Services defined herein as well as those services that may be requested and/or directed by Owners in the future. The Parties agree that all direct and indirect costs and expenses of all Services or other items to be provided under the Agreement shall be fully paid for by Owners according to the terms of this Agreement and this Exhibit C.
3. Domestic Labor : Service Provider shall bill U.S. based services with three components: [***].
   a. [***]
   b. [***]
   c. [***]
   d. [***]
   e. Westinghouse shall be paid [***] on domestic labor costs (the total of each bare labor wage times its applicable labor multiplier) under this Agreement.
4. Non-U.S. Based Labor : Service Provider shall bill non-U.S. based services on a [***] as follows:
   a. [***] engineering labor shall be billed at [***].
   b. [***] engineering labor shall be billed at [***].
5. Service Provider shall bill, and be reimbursed for, all project related travel expenses (incurred in accordance with its corporate Global Travel and Entertainment Policy), project related living allowances (incurred in accordance with its corporate US Domestic Assignment Procedure and Summary of VC Summer and Vogtle Domestic Assignment Package Terms and Conditions), and other direct costs as mutually agreed (to include but not be limited to reimbursement of project-specific insurance premiums and costs associated with and required transfers of regulatory permits), [***].
6. For Westinghouse, Service Provider shall bill all third party costs (vendors, subcontractors, materials, services, etc.) on a cost-reimbursable basis and shall be paid a [***].

7. For WECTEC, Service Provider shall bill all third party costs (vendors, subcontractors, materials and services, etc.) on a cost-reimbursable basis, [***].
8. Construction Equipment Rates
   a. For Service Provider owned construction equipment located on the Site as of the Effective Date, the Parties agree to a schedule of rates (included in Exhibit I (Rates for Leased Equipment)) based on [***]. Prior to the Effective Date, Owners will provide a schedule of Service Provider-owned construction equipment that Owners do not intend to use after the Effective Date which Owners may update from time to time throughout the term of this Agreement. Service Provider shall be responsible for demobilization of all Service Provider-owned equipment on Site after the Owners have informed Service Provider that Owners no longer intend to use this equipment; with the exception that for the Bigge Heavy Lift Derrick (HLD) crane, the Parties agree that:
      i. Owners shall be responsible to disassemble and load the HLD using Owner-provided craft and field non-manual staff and equipment;
      ii. Owners shall use best efforts to accomplish this demobilization as cost effectively as possible, will maintain demobilization-specific labor cost records, and will share these labor cost records with Service Provider;
      iii. Service Provider shall be responsible for the transportation arrangements and costs of the HLD components off-Site and their eventual disposition; and
      iv. [***]
   b. For leased construction equipment located on the Site as of the Effective Date, Owners will either assume Service Provider's existing equipment rental subcontracts, will obtain replacement equipment from other vendors, or Service Provider will provide existing leased equipment on a cost pass-through basis. For subcontracts or leases not assumed by Owners, Service Provider or equipment vendor will be responsible for demobilization of leased equipment that is on the Site as of the Effective Date provided under such subcontracts or leases.
9. [***].
10. [***].
11. [***]. Service Provider shall bill Owners for the Services performed under this Agreement to finish, update, develop, deliver, or provide the Deliverables in the same manner as for all other Services. The Parties agree to continue to negotiate

separate agreements with commercially reasonable terms typical to the nuclear industry for products that the Parties mutually agree fall outside the scope of this Agreement. [***].

12. [***]. Service Provider shall bill Owners for the Services performed under this Agreement to develop, provide access to, and deliver the Facility IP in the same manner as for all other Services.

13. Incentives. The Parties agree to pricing incentives that in the aggregate, permit Service Provider to earn an additional fee that in the aggregate, could total [***] of the amounts paid to Service Provider under this Agreement that is tied to the following performance incentives:

    a. Modules and engineered equipment and materials target cost savings sharing arrangement under which:

        i. The Parties will, prior to the Effective Date, agree to a target cost for costs to be incurred during the term of this Agreement for all Service Provider supplied modules and engineered equipment and materials.

        ii. The Parties acknowledge that the target cost may adjust during the term of this Agreement, and such adjusted target cost shall be applied for the purposes of this Exhibit. Prior to the Effective Date, the Parties will develop a mutually agreeable method for tracking such adjustments and re-establishing the target cost.

        iii. Upon completion of procurement activities for all Service Provider supplied modules and engineered equipment and materials:

            1. If Service Provider delivers all modules and engineered equipment and materials at a total cost [***] above the agreed target cost, Service Provider earns no cost savings sharing fee; or

            2. If Service Provider delivers all modules and engineered equipment and materials at a total cost [***] below the agreed modules and engineered equipment and materials target cost, Service Provider will earn cost savings sharing fee in an amount that is equal to the cost savings achieved that [***].

    b. Engineering target cost savings sharing arrangement. If Service Provider delivers all engineering services during the term of this Agreement at a total cost [***] below the agreed engineering target cost, Service Provider will earn cost savings sharing fee in an amount that is equal to the cost savings achieved that [***].

c. Engineering deliverables timeliness incentive fee ([***]), with specific deliverables and timeliness incentive fee dates and amounts to be mutually agreed.

d. First fuel load milestone achievement fee ([***]) should first fuel load occur at or prior to the scheduled fuel load date identified by Owners at conclusion of the Transition Period.

14. For services that are shared between the Vogtle and Summer AP1000 ® projects, Service Provider will apportion the billed amounts between the two projects.

15. a. Service Provider will receive an initial payment [***] of the Effective Date. The initial (and one-time) payment will approximate the first month's estimated costs. A true up of the initial payment to actual costs will be performed [***] of the initial payment. The difference between the initial payment and the first month's actual costs will be refunded (credited) to the Owners' account within the [***] of the Agreement term. The amount of the initial payment that is not refunded (credited) to the Owners' account [***] of the Agreement term will be paid back as follows:

    - [***];
    - [***]; and
    - [***].

    If either party terminates the Amended and Restated Services Agreement, the Service Provider will pay any portion of the initial payment not already paid to Owners' account within thirty (30) days.

    b. Service Provider will invoice once per month (by the 10th of the month) beginning in the first month of this Agreement. Payments will be due within 30 days of invoice date. For late payment, Service Provider shall be entitled to interest equal to the Prime Rate plus one percent (1%).

16. Invoices will be accompanied by reasonable detailed supporting documentation. At Owners' expense, Owners' independent auditor will have the right to examine on Service Provider's premises all reasonable information required by Owners to substantiate proper invoicing.

INVOICING

A. Invoices . Invoices for Services performed in a calendar month shall be transmitted to Owners on or before the tenth (10 th) day of the following month. Each invoice shall be accompanied by the following documentation sufficient to demonstrate Service

Provider's right to the amount of such payment: (i) employee summary billing information and costs tied to project work breakdown structure; (ii) detail for Service-Provider-owned equipment charges; (iii) invoices for rented equipment; and (iv) vendor invoices for material purchases, including material description per item, quantities per item, freight, sales taxes, the reason for the purchase and any additional similar information respecting the amount invoiced by the vendor.

B. Owners shall be responsible for all sales and use tax associated with the Services to be provided under this Agreement. However, if Service Provider is required by law to make any tax payments associated with Services to be provided under this Agreement, costs associated with such payments shall be passed through to Owners with no fee, adders, multipliers or interest.

C. Owners' payment of an invoice or portion thereof does not constitute approval or acceptance of any item or cost in that invoice nor shall it be construed to relieve Service Provider of any of its obligations under this Agreement. Payment shall not waive Owners' right to dispute an invoice.

D. Payment Disputes . If Owners determine that invoiced amounts are not due and payable to Service Provider, Owners shall notify Service Provider of Owners' objection to the invoice in writing, as provided in Article 19 (Dispute Resolution). Owners shall continue to pay all invoices during the pendency of negotiations or dispute resolution; provided, however, that in recognition of Owners' agreement to pay one hundred percent (100%) of all invoices, even disputed amounts, Service Provider agrees that a payment dispute shall not give Service Provider the right to stop work. Provided however, that failure to pay any invoice shall give Service Provider the right to stop work and to exercise its termination rights under the Agreement.

E. Lien Waivers . In order to be valid, each invoice submitted by the Service Provider must be accompanied by interim lien waivers and releases, in the form and substance as provided by Owners, executed by the Service Provider with respect to the Services completed prior to the date of such invoice.

F. Final Lien Release; Contractor's Affidavit . In order to be valid, Service Provider's invoice for the final payment from Owners under this Agreement must be accompanied by (i) lien releases and waivers executed by Service Provider in the form and substance as provided by Owners; and (ii) Service Provider's affidavit in the form and substance as provided by Owners executed by Service Provider; provided, however, to the extent that one or more disputed claims is identified on the final lien releases and waivers form, then the Service Provider's affidavit shall be provided contemporaneously with the resolution of such disputed claim(s).

Exhibit D
FORM OF STAFF AUGMENTATION AGREEMENT

STAFF AUGMENTATION AGREEMENT

This STAFF AUGMENTATION AGREEMENT ("Agreement"), effective as of _____________ (the "Effective Date") is entered into by and between **Westinghouse Electric Company LLC** , with offices in Cranberry Township, Pennsylvania ("Westinghouse"), **WECTEC Global Project Services Inc.** , with offices in Charlotte, North Carolina ("WECTEC" and collectively with Westinghouse, "Service Provider"), and **GEORGIA POWER COMPANY** , a Georgia corporation, for itself and as agent for **OGLETHORPE POWER CORPORATION (AN ELECTRIC MEMBERSHIP CORPORATION), MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA AND THE CITY OF DALTON** , Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, as Owners (collectively, the "Customer"). Both Customer and Service Provider are sometimes referred to herein individually as a "Party" and collectively as the "Parties".

WITNESSETH

WHEREAS, Owners and Service Provider entered into an agreement on July 20, 2017 ("Services Agreement") for Service Provider to provide services to Owners in connection with the development, design, procurement, construction and testing of two AP1000 ® nuclear units at the Vogtle Electric Generating Plant in Waynesboro, Georgia (the "Project"); and

WHEREAS, Customer and Service Provider desire to enter into an agreement under which seconded Service Provider personnel can be provided by Service Provider to work for Customer in order to support continued performance of work on the Project.

NOW THEREFORE, in consideration of the foregoing and the covenants herein recited, the Parties, intending to be legally and mutually bound, hereby agree as follows:

1. DEFINITIONS

1.1. **Candidates** shall mean any person referred to Customer by Service Provider to be considered as a potential Worker under this Agreement.

1.2. **Labor Rate** shall mean the agreed hourly labor rate for the Worker in question.

1.3. **Owners** shall mean Georgia Power Company; Oglethorpe Power Corporation (An Electric Membership Corporation); Municipal Electric Authority of Georgia; MEAG Power SPVJ, LLC; MEAG Power SPVM, LLC; MEAG Power SPVP, LLC; and The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners.

1.4. **Secondment Services** shall mean all work performed by Workers while seconded to Customer pursuant to this Agreement.

1.5. **Workers** shall mean the personnel employed by Service Provider and seconded to Customer pursuant to this Agreement.

2. STAFF AUGMENTATION

2.1 Provision of Workers

A. Customer may, from time to time, request from Service Provider Workers for Secondment Services to be performed. To request such Secondment Services, Customer shall issue a "Contract Labor Requisition Form" (a form of which is attached hereto as **Attachment 1**). The Contract Labor Requisition Form shall set forth any requirements for the Secondment Services to be performed including, but not limited to, the number of persons Customer believes are needed to perform the Secondment Services, the skill set, education, experience and qualifications of the Workers who would perform the Secondment Services, the specific types of Secondment Services to be performed, the expected duration of the Secondment Services, and the location (subject to Section 2.3B) where the Secondment Services would be performed. Customer may request specific Workers by name. Service Provider will use reasonable efforts to attempt to fulfill Customer's request for specifically-named Workers.

B. Service Provider shall then determine if it is able to fulfill, either fully or partially, Customer's request. If Service Provider is unable to fulfill a Customer request, then Service Provider shall notify Customer within ten (10) days of the receipt of Customer's request. If Service Provider is able to fully or partially complete Customer's request, then Service Provider will complete the Contract Labor Requisition Form by providing information such as the names of the Candidates to perform the Secondment Services, the Candidates' qualifications, the average salary for the function being performed, and estimated relocation costs (if any) and submit the completed Contract Labor Requisition Form to Customer within ten (10) days of the receipt of Customer's request. Customer shall then review such completed requisition within five (5) business days of receipt and shall accept or reject, in full or in part, in writing, Service Provider's completed requisition, as indicated on the Contract Labor Requisition Form for the designated Candidates. In the event any Candidate is rejected by Customer, Service Provider may submit a replacement Candidate within (5) business days for Customer's acceptance or rejection within (5) business days. Customer shall accept or reject, in writing, any Candidate.

C. If applicable, Service Provider shall be responsible for promptly gathering and transmitting to Customer all applications and supporting documentation for Candidates as necessary for Candidates to be evaluated by Customer to ensure compliance with NRC 10 C.F.R. Part 26, "Fitness for Duty Program" and related requirements, and Customer shall reimburse Service Provider for all associated reasonable, documented out-of-pocket expenses. Service Provider and Workers will adhere to Customer's Fitness for Duty policy and all other Customer policies. Service Provider agrees to notify Customer of any Candidate or Worker who has been denied access or removed from activities within the scope of 10 C.F.R. Part 26 at any nuclear power plant for violation of a Fitness for Duty policy. Notwithstanding anything to the contrary herein, Customer may reject any Candidate or require Service Provider to immediately terminate or reassign any Worker for failure to qualify under or for violation of Customer's Fitness for Duty policy.

E. Each Contract Labor Requisition Form issued by Customer for Secondment Services and accepted by Service Provider shall be governed by the terms and conditions of this Agreement and the Contract Labor Requisition Form. Each Contract Labor Requisition Form shall be independent of any previously issued or subsequently issued Contract Labor Requisition Form, unless specifically and expressly provided otherwise in a subsequently issued Contract Labor Requisition Form.

F. If applicable, Service Provider shall be responsible for promptly gathering and transmitting to Customer all applications and supporting documentation for Workers as necessary for Candidates to be evaluated by Customer to ensure compliance with NRC 10 C.F.R. Part 26, “Fitness for Duty Program” and related requirements, and Customer shall reimburse Service Provider for all associated out-of-pocket expenses. Service Provider agrees to notify Customer of any Candidate or Worker who has been denied access or removed from activities within the scope of 10 C.F.R. Part 26 at any nuclear power plant for violation of a Fitness for Duty policy. Notwithstanding anything to the contrary herein, Customer may reject any Candidate or immediately terminate or reassign any Worker for failure to qualify under or for violation of Customer’s Fitness for Duty policy. Customer reserves the right, in preparation for the declaration of a protected area for the Project, to specify additional requirements with respect to Fitness for Duty and access authorization for such proposed protected area, with the consent of Service Provider (which consent will not be unreasonably withheld).

2.2 Revision to Requested Secondment Services

Should Customer choose to amend any of the requirements of the Secondment Services to be performed for a particular Contract Labor Requisition Form, then it shall issue a new Contract Labor Requisition Form.

2.3 Personnel

A. Service Provider shall, for the Workers, pay all employment-related taxes, such as requirements for unemployment compensation, worker’s compensation for off-site activities, disability, required income and social security tax withholdings, and other legally mandated payments, for Workers provided by Service Provider. Customer shall have no liability or responsibility in this regard.

B. Workers may be located at the Project site or at any other location agreed in writing by the Parties.

C. Service Provider shall, for the Workers, handle all of the administration (including promptly obtaining any required work permits of any kind required for the Workers to perform the Secondment Services), medical needs/evacuation and travel in accordance with all appropriate laws and regulations. All required paperwork for any required Worker-related permits shall be promptly submitted by Service Provider or its Workers to ensure the timely access to the Project site in order to perform the Secondment Services. Service Provider shall not provide Workers who are foreign nationals as defined in 10 C.F.R. §810.3 without the

prior written consent of Customer. When Service Provider provides Workers who are not U.S. Citizens or legal residents of the United States, Service Provider shall comply with all U.S. laws regarding foreign nationals working in the United States, including, if applicable, the laws and regulations concerning the transfer of nuclear-related technology (See 10 C.F.R. Part 810). All out-of-pocket expenses incurred by Service Provider in obtaining all necessary immigration documents, visas, work permits, medical needs and travel expenses necessary for the Workers to perform the Secondment Services for Customer shall be considered Reimbursable Costs. Service Provider shall include the estimated cost of such expenses in its monthly invoice submitted to Customer pursuant to Section 4. Customer shall pay such amount, and such amount shall be subject to true-up, in accordance with Section 4.

D. Service Provider shall be solely responsible for all labor relations matters pertaining to all Workers described herein, including but not limited to, the selection, hiring, training, discipline, transfer, lay off, recall, promotion, reward, adjustment of grievances, compensation and retention in its employ of such personnel as Service Provider deems necessary in Service Provider's reasonable judgment to fulfill its duties and obligations herein. Customer will not be involved in the labor relations of Service Provider and, with respect to all persons engaged by Service Provider as Workers, will not nor attempt to exercise any of the foregoing labor relations responsibilities.

E. Customer and Service Provider shall assign coordinators for the purpose of providing local direction, decision-making and administration of this Agreement, as set forth in the table below:

Service Provider Corporate Coordinator: [TBC]	Customer Corporate Coordinator: [TBC]

The Service Provider Corporate Coordinator duties will include:

- Receiving and responding to all Contract Labor Requisition Forms;
- Actively participating in Customer's strategic resource planning activities;
- Being Customer's primary point of contact for this Agreement; and
- Providing reasonable and necessary assistance to resolve any payment/invoice discrepancies.

2.4 No Guarantee of Positions or Workers

The Parties agree that there is no guaranteed number of open positions, either expressed or implied, that will be requested by Customer. The Parties also agree that there is no guarantee that Service Provider will be able to fill any or all of Customer's open positions.

2.5 Replacement of Workers

Customer shall have the right to request Service Provider to remove, replace or reassign any Worker for cause after notice of same. Upon receipt of Customer's notice, Service Provider shall promptly comply with such notice, subject to compliance with applicable

state and federal law and any relevant rules and regulations promulgated thereunder and, if available, provide replacement Candidates for Customer's review and approval in accordance with Section 2.1.

2.6 Service Provider Remains Employer

Although Service Provider shall retain no right to direct, supervise or control the activities of Workers at the Project site, Workers shall remain at all times on Service Provider's payroll and participate in Service Provider's employee benefit programs, if eligible, and Service Provider may communicate with Workers for administrative purposes. Service Provider shall be responsible for the payment of Workers' salaries or wages, payroll taxes and employee benefits, and for maintaining workers' compensation insurance coverage for Workers. Service Provider shall indemnify, defend and hold Customer, Owners and their affiliates, and the respective officers, employees and agents thereof, harmless from and against any and all claims, losses, damages, liabilities, legal fees and expenses resulting from or arising in connection with any failure to pay such wages or benefits, or to withhold appropriate taxes as required hereby.

2.7 Responsibility for Work Product

Because Workers will be under the exclusive direction, supervision and control of Customer at the Project site, Service Provider shall have no liability to Customer for loss or damage arising out of or resulting from the activities of Workers at the Project site while seconded to Customer, including but not limited to, costs of re-performance or rework, injury to or death of persons, loss of or damage to property including property of Owners or others. Service Provider shall have no liability to Customer, Owners or others who may use or benefit from the work or Secondment Services of the Workers for any professional error or omission, workmanship deficiency, or direct or consequential losses or damages of any other kind arising from the activities of Workers at the Project site.

3. RELATIONSHIPS WITH WORKERS

3.1 Independent Contractor Status

The Parties expressly intend and agree that Service Provider is acting as an independent contractor, and neither Service Provider nor any Worker is an agent or employee of Customer. Nothing in this Agreement shall be construed or implied to create a relationship of partners, agency, joint ventures or of employer and employee as between Service Provider and Customer. Further, neither Service Provider nor its personnel, agents, subcontractors nor Workers have any authority whatsoever, expressed or implied, by virtue of this Agreement, whereby such persons or entities are authorized to commit Customer, in any way, to perform in any manner or to pay money for purchased services or materials.

3.2 Service Provider Employees

The Parties agree that in the performance of this Agreement, the Workers shall remain solely as employees of Service Provider. Service Provider is responsible for the hiring, termination and administrative management, but not Project site management, of all such Workers. Customer shall not be obligated to provide Service Provider or the Workers with any of the rights and privileges established for Customer's employees. If a secondment is terminated by Customer prior to the anticipated end of the secondment, then Customer shall be responsible for the costs to return such Worker to his or her point

of origin and the costs to replace such terminated Worker, if required, and Customer shall reimburse Service Provider directly for all such costs.

3.3 Control of Work Sites

Customer shall at all times maintain full control of the work sites at the Project, including the direction of the Workers while the Workers are performing Secondment Services for Customer. Customer shall provide all necessary direction to Workers assigned to their respective work sites at the Project in order to properly complete the Secondment Services.

3.4 Day-to-Day Control

Workers shall be under the exclusive direction, supervision and control of Customer during such times as such Workers are seconded under this Agreement, and Service Provider shall retain no right to supervise, direct or control such Workers during such times. At no time during performance of specific or assigned tasks shall the Workers receive or act under instructions from Service Provider. The Workers shall comply with the applicable Project and office rules, regulations, and safety procedures and with all applicable laws and regulations including export control laws and regulations. If appropriate for the assignment, Customer shall be responsible for providing appropriate employee support functions and facilities such as office space that are similar to the facilities provided for other personnel similarly situated at that location and shall provide all needed office or site facilities, Information Systems & Technology computer and communication equipment, software, telephone, small tools, reprographics, supplies and support services for Workers working at the Project site.

3.5 Termination

In addition to the right to immediate dismissal under Section 2.5, Customer may terminate the secondment of any Worker at any time upon providing five (5) days' advance notice to Service Provider or its local representative, if any.

4. COMPENSATION

Pricing, rates and invoicing will be handled by the applicable terms in the Services Agreement.

5. EQUIPMENT AND FACILITIES

5.1 Furnished Equipment

Customer shall, at no cost or expense to Service Provider, provide all necessary computers, mobile phones, office space, tools, equipment, patterns, scaffolding, rigging, supplies, materials, and protective clothing which are or may be required for the Workers to provide Secondment Services in accordance with the terms of this Agreement and the directions of Customer for so long as this Agreement is in effect.

5.2 Work Practices

A. Customer will cause the Workers to comply with the standard work practices established at the Project site and any other site at which the Workers are performing Secondment Services. Such standard work practices will be provided in writing to the Workers providing Secondment Services at the Project site. These standard work practices shall include, but not be limited to, safety policies

and regulations, security and cyber security policies and regulations, Fitness for Duty, quality concerns, quality control, quality assurance, radiation protection and control, environmental compliance and regulatory compliance, communications, work hours, use of cafeteria, medical facilities (if any), dress codes, phones, faxes and copy machines. Customer shall promptly notify the Workers, in writing, of any changes in such policies and procedures that are relevant to the Workers.

B. The Parties acknowledge that Workers' movements through accessible areas of a facility or plant may require that authorized personnel escort individuals that have not been accorded unescorted access status. Workers who require unescorted access to Customer's facilities will be screened by Customer in accordance with applicable regulatory and industry requirements.

6. QUALITY REQUIREMENTS

6.1 Quality Assurance

Customer shall cause the Workers to perform Secondment Services in accordance with the Quality Assurance Program provided by Service Provider to Customer under the Services Agreement, the details of which shall be provided, in writing, to the Workers.

6.2 Procurement of Secondment Services Related to Digital Computer and Communication Systems and Networks

A. Any Secondment Services furnished under this Agreement that are classified as cyber security related shall be subject to the controls of Customer's Quality Assurance and cyber security programs. The details, policies and requirements of such program will be provided to Workers prior to performing cyber security related Secondment Services.

B. When providing Secondment Services on critical digital assets (hardware, firmware, operating systems, or application software) at Customer's or Owners' facilities, each Worker agrees to abide by Customer's cyber security program as follows:

1. Before beginning permitted access to Customer's network, each Worker shall be made aware of Customer's cyber security program and must agree to abide by the relevant policies.
2. To participate in Customer's cyber security training programs or equivalent qualification from Service Provider.
3. To adhere to the following Customer cyber security policies:
   (a) Configuration management of the Service Provider's computers, to include virus protection, patch management, authentication requirements and secure internet connections.
   (b) Maintain secure transfer and storage of information and code while off-site.
   (c) Duty to protect confidentiality.
   (d) Software quality assurance ("SQA") procedures.
   (e) Approved and disapproved software requirements tabulation.
   (f) Requirements and procedures for background investigations.

7. INSURANCE

7.1. Customer and Service Provider Insurance

If applicable, the insurance requirements of the Services Agreement are incorporated herein.

7.2 Additional Insurance

Customer may require Service Provider at any time, and from time to time during the term of this Agreement, to obtain and maintain in force additional insurance with coverage or limits in addition to those otherwise mandated above. The cost of premiums for any such additional insurance shall be considered a Reimbursable Cost and shall be invoiced to Customer in accordance with the invoicing and payment-related provisions in the Services Agreement, including Exhibit C (Rates and Invoicing). Service Provider shall provide the estimated cost of premiums for any requested additional insurance to Customer in writing for approval and, if approved, Service Provider will include the premiums in its monthly invoice submitted to Customer pursuant to Section 4.

8. TERM AND TERMINATION

8.1 Term

Unless earlier terminated pursuant to Section 8.2, the term of this Agreement shall be effective on the Effective Date and be effective through the first to occur of (a) expiration of the term (as defined in the Services Agreement) of the Services Agreements and (b) termination of the Services Agreement.

8.2 Termination

Either Party may terminate this Agreement for convenience upon thirty (30) days' advance-written notice to the other Party; *provided* that the term of this Agreement shall not extend beyond the date of termination of the Services Agreement.

8.3 Close-out

In the event of a termination of the secondment of any individual Worker by Customer, Service Provider shall comply promptly with instructions and directives contained in such notice regarding the demobilization of the Worker(s) as of the date of termination, as specified in the notice, and demobilization costs of such Worker(s) will be handled in accordance with the terms of the Services Agreement.

9. RELEASE AND INDEMNITY

9.1 Customer Indemnity

Customer agrees to defend, indemnify and hold harmless, Service Provider and Workers from and against any and all third party claims, losses, damages, liabilities, legal fees and expenses, resulting from or arising in connection with the activities of Workers while on assignment pursuant to this Agreement and under the direction, supervision and control of Customer.

9.2 Indemnification Conditions

If any claim arises with respect to which the Service Provider believes it is entitled to indemnification, the Service Provider shall give written notice of such claim and a copy of such claim, process, and all legal pleadings with respect thereto (to the extent available

to the Service Provider) to Customer within a reasonable period of time of being served with such claim, process, or legal pleading. Failure to give such notice in a timely manner shall not diminish the indemnification obligations of Customer except to the extent the failure or delay in giving such notice results in actual and material prejudice to Customer.

10. CONFIDENTIAL INFORMATION AND INTELLECTUAL PROPERTY

10.1 Confidentiality of the Workers

Service Provider agrees that Customer may require Workers to execute non-disclosure agreements to protect Customer's or others' confidential information.

10.2 Confidentiality between the Parties

The provisions of Article 14 of the Services Agreement respecting the treatment of Confidential and Proprietary Information shall apply to all Secondment Services. Article 14 of the Services Agreement is expressly incorporated into this Agreement as if it were fully set out herein.

10.3 Ownership of Work Product and Intellectual Property

Without limiting either Party's rights and obligations with respect to the "Confidential and Proprietary Information" (as defined in the Services Agreement), all drawings and other data prepared by any Workers shall be and remain the property of Customer, or its designee, and may be used for any and all present and future project or purposes Customer deems advisable without payment to Service Provider or such Worker of any sum in excess of the compensation specified herein and without any claim or right thereon by Service Provider or any Worker. Any and all inventions, discoveries and improvements which any Worker conceives of or makes, in whole or in part, working alone or jointly with others during the period of their secondment to Customer, which relate to Customer's business or arise out of, or result from the Secondment Services performed by the Worker shall be the sole and exclusive property of Customer, or Customer's designee. Service Provider hereby agrees to, and by these presents does, assign, transfer and convey to Customer, or to Customer's designee, any such intellectual property rights in any invention, discoveries and improvements.

10.4 Survival

The terms and covenants of this Section 10 shall survive the termination or expiration of this Agreement.

11. RIGHT OF ASSIGNMENT

Assignment of this Agreement is governed by the assignment terms in the Services Agreement.

12. DELAYS

12.1 Force Majeure

Except for Customer's obligation to make payment to Service Provider, neither Customer nor Service Provider shall be considered in default in the performance of its obligations hereunder to the extent that the performance of any such obligation is prevented or delayed by any cause beyond its reasonable control, including acts of God, strikes or other labor disputes, fires, floods, hurricanes, earthquakes, wars and actions or inaction of governmental authorities.

12.2 Notice

In the event that either Customer or Service Provider shall become aware (hereinafter the "Delinquent Party") of an actual or potential delay in the performance of all or any portion of its contractual obligations, such Delinquent Party shall promptly give notice thereof to the other Party. The Delinquent Party shall promptly take such measures as may be necessary to prevent or minimize such delay and shall promptly notify the other Party in writing of the measures intended to be taken.

13. DISPUTE RESOLUTION

All disputes connected with, arising out of or relating to the subject matter of this Agreement, including concerning a breach hereof, the obligation of either Party hereunder, or the interpretation of any provision hereof, shall be subject to the procedure described in Article 19 of the Services Agreement. Article 19 of the Services Agreement is expressly incorporated into this Agreement as if it were fully set out herein.

14. COMPLIANCE WITH LAWS

14.1 Compliance with Laws

Each Party hereto shall comply at all times with applicable executive orders and federal, state, municipal and local laws applicable to the location in which the Secondment Services or this Agreement is performed; as well as all applicable rules, orders, requirements and regulations thereunder.

14.2 NRC Regulations

Service Provider acknowledges that, in connection with its provision of Workers under this Agreement, it and its personnel, agents and subcontractors may be subject to laws, regulations and policies involving matters within the regulatory responsibility of the U.S. Nuclear Regulatory Commission (the "NRC"). These laws, regulations, and policies include Section 211 of the ERA, 10 C.F.R. § 50.7, the NRC's May 14, 1996 Policy Statement of "Freedom of Employee in the Nuclear Industry to Raise Safety Concerns Without Fear of Retaliation" (61 Federal Register 24336), and the NRC's "Final Safety Culture Policy Statement" (June 14, 2011). The Parties agree to abide by such laws, regulations and policies, agree to maintain a working environment where Workers are free to raise safety concerns, and agree to not harass, intimidate, take adverse employment action against, or otherwise retaliate against any Worker because they bring or have brought matters related to this Agreement or related to the facility or location to which they are assigned or similar matters to the attention of the NRC, any state authority possessing authority delegated from the NRC, the U.S. Department of Labor or to any representative of Customer or to any other person or third party.

14.3 Additional NRC Requirements

The Parties acknowledge that certain provisions of the NRC's Confirmatory Order issued on September 25, 2014 to the Chicago Bridge and Iron Company (the "Confirmatory Order") may apply to Workers under this Agreement, and, if applicable, agree to adhere to applicable provisions of the Confirmatory Order.

14.4 Notice of Retaliation

During the term of this Agreement, each Party agrees to notify the other Party, promptly in writing, when such Party becomes aware of any instance in which any Worker, in connection with the provision of this Agreement, files a claim at the U.S. Department of Labor or with the NRC, or any other governmental authority possessing authority delegated from the NRC, alleging that the employee or Worker has been harassed, intimidated, retaliated against or otherwise discriminated against for having engaged in activities involving this Worker that are protected as described hereunder. Each Party further agrees to notify the other Party promptly in writing when it becomes aware of any investigation undertaken by the NRC's Office of Investigation into activities under this Agreement and of the material progress of such an investigation. Each Party also agrees to notify the other Party promptly in writing of the material progress of the action involving such filed claim or allegation and any decision, whether preliminary or final, by the U.S. Department of Labor, the NRC or any other governmental authority possessing authority delegated from the NRC in any case involving such claim or allegation.

14.5 Non-Discrimination

Each Party hereto agrees that it will not discriminate against its employees, agents or subcontractors, applicants for employment or engagement in providing or accepting Workers hereunder or Candidates it considers for secondment in connection with the Secondment Services described herein based on race, marital status, religion, color, national origin, sex, age, disability or veteran status.

15. WARRANTY

15.1 Warranty

Service Provider represents and warrants that all Workers furnished to Customer, in response to filling specific job descriptions within this Agreement have the professional qualifications requested by Customer as stated in the Contract Labor Requisition Form. Service Provider shall, conditioned upon the availability of qualified Workers, at its sole expense, promptly replace any Worker who does not meet the foregoing warranty. Notwithstanding the foregoing, Customer shall have the right to immediately dismiss any Worker who fails to perform requested work in accordance with accepted regulatory and professional standards applicable to the job classification for which the Worker was seconded.

15.2 Sole and Exclusive Remedies

THE WARRANTIES SET FORTH HEREIN ARE EXCLUSIVE AND IN LIEU OF ALL OTHER WARRANTIES WHETHER STATUTORY, EXPRESS OR IMPLIED(INCLUDING ALL WARRANTIES OF MERCHANTABILITY AND FITNESS FOR PURPOSE AND ALL WARRANTIES ARISING FROM COURSE OF DEALING OR USAGE OF TRADE). THE REMEDIES SET FORTH, FOR THE TIME AND IN THE MANNER PROVIDED ABOVE, SHALL BE CUSTOMER'S

EXCLUSIVE REMEDIES FOR FAILURE OF SERVICE PROVIDER TO MEET ITS WARRANTY OBLIGATIONS, WHETHER BASED IN CONTRACT, IN TORT (INCLUDING NEGLIGENCE AND STRICT LIABILITY), OR OTHERWISE.

16. TAXES

The rates and charges herein include all taxes except: any federal taxes imposed or increased (to the extent of the increase) after the Effective Date of this Agreement; any state or local sales, use, gross receipts, duty, value added, excise, or similar taxes now or hereafter imposed. All of the aforementioned taxes are not included in the price and will be the responsibility of Service Provider.

17. MISCELLANEOUS

17.1 Notices

Any notices pursuant to default, cancellation, termination or otherwise required pursuant to this Agreement shall be sent by recognized overnight courier service, registered or certified mail, or via email with receipt confirmed in writing to the Parties at the addresses shown below:

If to Customer:
Georgia Power Company
Attn: ______________________
____
____
Email: _____________________

If to Service Provider:
Westinghouse Electric Company LLC
Attn: ______________________
____
____
Email: _____________________

WECTEC Global Project Services Inc.
Attn: ______________________
____
____
Email: _____________________

Either Party may change all or any part of its address for providing notices upon submitting such change to the other Party in accordance with the requirements of this Section.

17.2 Choice of Law

This Agreement shall be construed and interpreted in accordance with the laws of the State of New York, excluding its choice of law rules.

17.3 Limit of Liability

WITH THE EXCEPTION OF SERVICE PROVIDER'S INDEMNITY OBLIGATIONS UNDER SECTION 2.6 OF THIS AGREEMENT, SERVICE PROVIDER'S

CUMULATIVE AGGREGATE LIABILITY TO CUSTOMER AND OWNERS FROM ANY AND ALL CAUSES ARISING OUT OF OR IN CONNECTION WITH THIS AGREEMENT SHALL NOT EXCEED ONE MILLION DOLLARS ($1,000,000).

NEITHER CUSTOMER, OWNERS NOR SERVICE PROVIDER NOR THEIR AFFILIATES (NOR ANY OF SUCH PARTY'S OR AFFILIATE'S RESPECTIVE OFFICERS, AGENTS, SERVANTS, EMPLOYEES, SHAREHOLDERS, OR MEMBERS) WILL BE LIABLE TO THE OTHER PARTY OR THEIR AFFILIATES (NOR ANY OF THEIR RESPECTIVE OFFICERS, AGENTS, SERVANTS, EMPLOYEES, SHAREHOLDERS, OR MEMBERS) FOR ANY SPECIAL, INDIRECT, INCIDENTAL OR CONSEQUENTIAL LOSS OR DAMAGE WHATSOEVER, ARISING OUT OF THIS AGREEMENT, INCLUDING, BUT NOT BE LIMITED TO, LOSS OF USE OR OPPORTUNITY, LOST PROFITS, ANTICIPATED INCOME, COSTS OF CAPITAL, OR SIMILAR LOSS.

THE RELEASES FROM AND LIMITATIONS ON LIABILITY AND INDEMNITY OBLIGATIONS EXPRESSED IN THIS AGREEMENT SHALL APPLY EVEN IN THE EVENT OF THE FAULT OR NEGLIGENCE OF THE RELEASED OR INDEMNIFIED PARTY, AND WHETHER LIABILITY IS FOUNDED IN CONTRACT, TORT, STRICT LIABILITY, OR OTHER BASIS OF LIABILITY, AND SHALL EXTEND TO SUCH PARTY AND ITS AFFILIATES AND EACH OF THEIR RESPECTIVE SHAREHOLDERS, DIRECTORS, OFFICERS, EMPLOYEES AND AGENTS.

17.4 Entire Agreement; Binding Effect

The Parties hereto enter into this Agreement intending to be legally bound hereby. This Agreement represents the entire contract between the Parties with respect to the subject matter hereof. This Agreement may not be modified except by a modification, in writing, which has been executed by authorized representatives of both Customer and Service Provider. Any modifications to the contrary shall have no force and effect. This Agreement shall be binding upon the Parties hereto and their respective permitted successors and assigns.

17.5 No Waiver

The failure of either Party to enforce at any time any of the provisions of this Agreement shall in no way be construed as a waiver of such provision(s) or in any way affect the validity of this Agreement or any part hereof, or a Party's rights and obligations hereunder, or the right of any Party to thereafter enforce each and every provision hereof.

17.6 Severability

Should any provision of this Agreement be found or adjudged to be unenforceable, the remaining provisions hereof shall remain in full force and effect.

17.7 Headings

The use of headings in this Agreement is for convenience of the Parties only and shall have no legal effect.

17.8 Publicity

Service Provider shall not make or permit the making of any public statements or announcements concerning this Agreement or the relationship of the Parties with respect

to the Project, without the Customer's prior written approval, which may be given or withheld in its sole discretion.

17.9 Survival

The provisions of this Agreement which by their nature survive acceptance, performance and termination or expiration of the Secondment Services, including, without limitation, the provisions concerning payment, indemnity, warranty, limitation of liability, confidentiality and trade secrets and proprietary rights, will remain in full force and in effect following termination, cancellation, completion or expiration of this Agreement.

17.10 Counterparts

This Agreement may be executed in counterparts, each of which shall be deemed an original, but all of which together shall be deemed to be one and the same agreement. A signed copy of this Agreement delivered by facsimile, e-mail or other means of electronic transmission shall be deemed to have the same legal effect as delivery of an original signed copy of this Agreement.

SIGNATURE PAGE FOLLOWS

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in duplicate by their duly authorized representatives:

CUSTOMER:	SERVICE PROVIDER:
SOUTHERN NUCLEAR OPERATING COMPANY, INC. ____________________ (sign here) ____________________ (print name) ____________________ TITLE ____________________ (date)	WESTINGHOUSE ELECTRIC COMPANY LLC ____________________ (sign here) ____________________ (print name) ____________________ TITLE ____________________ (date)
	WECTEC GLOBAL PROJECT SERVICES INC. ____________________ (sign here) ____________________ (print name) ____________________ TITLE ____________________ (date)

ATTACHMENT 1

Contract Labor Requisition Form

CUSTOMER NAME: _______ DATE OF REQUEST: ______

JOB SITE: ______

REQUESTED START DATE: _______ ANTICIPATED END DATE: ______

NUMBER & TYPE OF WORKERS REQUESTED

Title	Number

TOTAL NUMBER OF WORKERS REQUESTED: ______

QUALIFICATIONS

Experience:
Skills:
Education:
Licenses & Other Requisite Qualifications:

SECONDMENT SERVICES TO BE PERFORMED (INCLUDING ANY DELEGATIONS OF AUTHORITY)

EXHIBIT E
CONFIDENTIALITY AGREEMENT

THIS CONFIDENTIALITY AGREEMENT (this "Agreement") is made as of the ___ day of _____________, 20__, by and between ___________________ (the "Disclosing Party') and ________________ (the "Recipient").

WHEREAS , the Disclosing Party is a party to an Amended and Restated Services Agreement, dated as of July 20, 2017, between Georgia Power Company, for itself and as agent for Owners [1] , with Westinghouse Electric Company LLC and WECTEC Global Project Services Inc. (together "Westinghouse") under which Westinghouse will perform certain agreed-to services for Disclosing Party directed to the completion of the Vogtle 3 & 4 nuclear power plants ("Agreement"); and

WHEREAS , the Disclosing Party has been provided with certain confidential and/or proprietary information ("Confidential and Proprietary Information") of Westinghouse or Owners, which the Disclosing Party desires to disclose to the Recipient as permitted in accordance with the provisions of the Agreement; and

WHEREAS , under the terms of the Agreement, the Disclosing Party and the Recipient are required to enter into this Agreement as a condition to disclosure of such Confidential and Proprietary Information to the Recipient.

NOW THEREFORE , for and in consideration of the premises and the mutual promises hereinafter set forth and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto hereby agree as follows:

1. Recipient shall maintain the confidentiality of all Confidential and Proprietary Information disclosed to it hereunder, and shall not use such Confidential and Proprietary Information for any purpose other than the purposes of Facility (and associated simulators) construction, testing, completion and defense of ITAACs, startup, trouble-shooting, response to plant events, inspection, evaluation of system or component performance, scheduling, investigations, operation, maintenance, training, repair, licensing, modification, decommissioning and compliance with laws or the requirements of governmental authorities (the "Purpose").

[1] Owners are defined as Georgia Power Company, a Georgia Corporation, Oglethorpe Power Corporation (An Electric Membership Corporation), an electric membership corporation formed under the laws of the State of Georgia, Municipal Electric Authority of Georgia, a public body corporate and politic and an instrumentality of the State of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, each a Georgia limited liability company, and The City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light and Sinking Fund Commissioners. Southern Nuclear Operating Company, Inc. ("SNC") is the licensed operator of Vogtle 3 and 4 and is Owners' agent for the purposes of implementation and administration of the Services Agreement.

2. Recipient shall not transmit or further disclose such Confidential and Proprietary Information to any third party, including, without limitation, parent organizations of Recipient, sister organizations of Recipient, subsidiaries of Recipient, consultants of Recipient or subcontractors of Recipient.

3. In the event that the Recipient or any of its representatives are requested or required in any proceeding or by any governmental authority to disclose any of the Confidential and Proprietary Information, the Recipient shall provide the Disclosing Party with prompt written notice of such request or requirement so that the Disclosing Party may seek a protective order or other appropriate remedy and/or waive compliance with the provisions of this Agreement. If, in the absence of a protective order or other remedy or the receipt of a waiver from the Disclosing Party, the Recipient or any of its representatives are nonetheless, in the written opinion of their counsel, legally compelled to disclose such information, it or its representatives may, without liability hereunder, disclose only that portion of the Confidential and Proprietary Information which such counsel advises the Recipient is legally required to be disclosed, provided that the Recipient exercises its best efforts to preserve the confidentiality of the Confidential and Proprietary Information, including, without limitation, by cooperating with the Disclosing Party to obtain an appropriate protective order or other reliable assurance that confidential treatment will be accorded the Confidential and Proprietary Information.

4. Except where necessary in furtherance of the Purpose, Recipient shall not make any copy or in any way reproduce or excerpt such Confidential and Proprietary Information except as authorized by the Disclosing Party in writing prior to such reproduction or excerption. Any such copies or excerpts shall include all proprietary notices and designations. Upon the written request of the Disclosing Party, the Confidential and Proprietary Information provided hereunder and any such copies or excerpts thereof shall be returned to the Disclosing Party, or, at the sole option and request of the Disclosing Party, Recipient shall destroy such information and any such copies and/or excerpts and certify in writing to the Disclosing Party that such information has in fact been destroyed.

5. Nothing herein shall apply to any information which is:

(a) now generally known or readily available to the trade or public or which becomes so known or readily available without fault of the Recipient; or

(b) rightfully possessed by the Recipient without restriction prior to its disclosure hereunder by the Disclosing Party; or

(c) acquired from a third party without restriction, provided that the Recipient does not know, or have reason to know, or is not informed subsequent to disclosure by such third party and prior to disclosure by the Recipient that such information was acquired under an obligation of confidentiality.

6. It is mutually understood that nothing herein shall be construed as granting or implying any right under any letters patent, or to use any Confidential and Proprietary Information claimed therein, or as permitting Recipient to unfairly obtain the right to use

Confidential and Proprietary Information which becomes publicly known through an improper act or omission on its part.

7. The Owners, Westinghouse and WECTEC make no warranty or representation whatsoever to the Recipient as to the sufficiency or accuracy of the Confidential and Proprietary Information provided hereunder, the ability of Recipient to use the Confidential and Proprietary Information for its intended purpose, or as to the result to be obtained therefrom.

8. Neither the Owners, Westinghouse, WECTEC, nor their suppliers or subcontractors of any tier shall be liable with respect to or resulting from the use (or the results of such use) or misuse of any Confidential and Proprietary Information furnished hereunder.

9. Nothing in this Agreement shall obligate the Disclosing Party to provide any specific information that it otherwise desires to withhold.

10. Recipient agrees to fully comply with all laws and regulations with regard to the Confidential and Proprietary Information transmitted hereunder.

11. Recipient shall not, at any time file, cause or authorize the filing of any patent application in any country in respect of any invention derived from the Confidential and Proprietary Information supplied hereunder.

12. Recipient shall indemnify and hold the Disclosing Party harmless from and against all losses, liabilities, costs and expenses (including reasonable attorneys' fees) arising out of or related to any disclosure of Confidential and Proprietary Information by Recipient in violation of this Agreement.

13. Recipient shall not assign this Agreement. This Agreement shall be binding upon the Recipient and its successors and shall benefit and be enforceable by the Owners, Westinghouse or WECTEC and each of their respective successors and assigns.

14. If any of the terms of this Agreement are violated by Recipient, the Owners, Westinghouse or WECTEC shall be entitled to an injunction to be issued by any court of competent jurisdiction, enjoining and restraining the Recipient, as well as damages and any costs of collection, including but not limited to attorneys' and other professionals' fees and related charges and interest.

15. If any provision of this Agreement is held invalid in any respect, it shall not affect the validity of any other provision of this Agreement. If any provision of this Agreement is held to be unreasonable as to the time, scope or otherwise, it shall be construed by limiting and reducing it so as to be enforceable under then applicable law.

16. This Agreement shall be governed in accordance with the laws of the State of New York without giving effect to any choice of law, provision, or rule (whether of New York or

any other jurisdiction) that would cause the application of the laws of any jurisdiction other than New York.

IN WITNESS WHEREOF , the parties have hereto set their respective signatures to this Agreement.

DISCLOSING PARTY :

By: ________________________
Name: ______________________
Title: _______________________
Address: ____________________

RECIPIENT :

By: ________________________
Name: ______________________
Title: _______________________
Address: ____________________

EXHIBIT F
FACILITY IP LICENSE IN THE EVENT OF A TRIGGERING EVENT

This FACILITY IP LICENSE IN THE EVENT OF A TRIGGERING EVENT ("Facility IP License") is made as of July 20, 2017 ("Execution Date"), and becomes effective as of the Effective Date as defined in the Amended and Restated Services Agreement, by and between, on the one hand, GEORGIA POWER COMPANY, a Georgia corporation, for itself and as agent for Owners, as defined below, and, on the other hand, WESTINGHOUSE ELECTRIC COMPANY LLC, a Delaware limited liability company having a place of business in Cranberry, Pennsylvania ("WEC"), and WECTEC GLOBAL PROJECT SERVICES INC., a Louisiana corporation having a place of business in Charlotte, North Carolina ("WECTEC" and together with WEC, the "Service Provider"). Owners and Service Provider may be referred to individually as a "Party" and collectively as the "Parties."

1. Definitions .

For purposes of this Facility IP License, the terms listed below shall have the meanings indicated beside them. Capitalized terms not otherwise defined below shall have the meanings ascribed to them in the Amended and Restated Services Agreement between the Parties of even date herewith (together with all Exhibits thereto, as amended or modified and as may be further amended or modified from time to time, the "Services Agreement").

(a) "Facility IP" means all Intellectual Property (and associated deliverables, products, and other materials described in this definition) of Service Provider or its Affiliates, whether now existing or hereafter developed, in or covering the Facility (including all equipment, components, hardware, software and other deliverables) as delivered under the Services Agreement or under the EPC Agreement (including Intellectual Property, deliverables, products, and materials underlying, supporting, or used to create deliverables under the EPC Agreement or Services Agreement, regardless of whether the same have been or will be provided to Owners, but excluding products delivered by Service Provider's fuels group to Owners under separate commercial agreements), required or reasonably necessary for Owners to design, construct, test, startup, license, complete, maintain, improve, and operate the Facility, to defend challenges on ITAACs or respond to other requests made by any Government Authority or pursuant to applicable Law, including (i) patents, trademarks (but excluding the Westinghouse name or any trademarks related to AP1000 ®), copyrights, trade secrets, inventions, know-how, proprietary information, confidential information, documentation, materials and data; (ii) software required or reasonably necessary for Facility Purposes, including Service Provider (or its Affiliates)-owned and developed proprietary computer programs expressed in a source code language consisting of a full source language statement of programs and all related compiler command files, build scripts, complete maintenance documentation, application programming interfaces, graphical user interfaces, schematic diagrams and annotations which comprise the pre-coding detail design specifications, information management data bases (e.g., open item database, PCC outstanding issues list, DCP database, LAR database, ITAAC database), plans, designs, calculations and models (e.g., seismic models, structural models, stress analyses,

hazards analyses – flooding, PRHA, probabilistic risk assessment, etc.), design basis information, computer source code for CYS monitoring system and all CYS design documents, cyber security databases (e.g., CDA identification database, LRM assessment database, cyber SharePoint site, etc.) and all cyber security supporting documentation, simulator designs; (iii) all AP1000 ® -related schematics, designs and information, included but not limited to AP1000 ® information referenced in the DCD or COL; and (iv) all other information, documentation, materials, data, technology, software and other property necessary to allow a reasonably skilled person to design, construct, test, license, startup, operate, improve, complete and maintain the Facility.

(b) "Intellectual Property" means any and all intellectual property rights existing from time to time under any Law including patent law, copyright law, semiconductor chip protection law, moral rights law, trade secret law, trademark law (together with all goodwill associated therewith (but excluding any rights to the Westinghouse name or any trademarks related to AP1000 ®)), unfair competition law, publicity rights law, or privacy rights law, and any and all other proprietary rights, and any and all applications, renewals, extensions and restorations of any of the foregoing, now or hereafter in force and effect worldwide. For purposes of this definition, rights under patent laws shall include rights under any and all United States patent applications (and patents issued therefrom) and patents (including letters patent and inventor's certificates), including, without limitation, any provisionals, substitutions, extensions, supplementary patent certificates, reissues, renewals, divisions, continuations in part (or in whole), continued prosecution applications, requests for continued examination, and other similar filings or stages thereof provided for under the laws of the United States.

(c) "Owners" means Georgia Power Company, Oglethorpe Power Corporation (An Electric Membership Corporation), Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners.

(d) "Software" or "software" means any computer programming code (such as computer programs, procedures, rules or routines embodied in computer programs, databases and related computer files) consisting of instructions or statement in a form readable by individuals (source code) or machines (object code) and related documentation and supporting materials therefor, in any form or medium, including electronic media. Software includes any bug fixes, error-correction releases, updates, upgrades, enhancements, modifications, changes, new versions and replacements therefor.

(e) "Triggering Event" means Service Provider's complete failure to perform the Services under the Services Agreement for an uninterrupted period of at least fifteen (15) days, following written notice by Owners to Service Provider of such failure to perform the Services and after Service Provider has been granted reasonable opportunity and period of time under the circumstances (not to exceed sixty (60) days) to resume provision of the Services and fails to do so; provided, however, that Owners shall not be required to wait any period of time in the event Service Provider has publicly stated its abandonment of its obligations under the Services Agreement or Service Provider cannot provide any reasonable assurance that Service Provider will resume provision of the Services. As used herein, "complete failure" shall mean (a) failure

by Service Provider to perform all of the Services requested by Owners (including delivery of Licensed IP (as that term is defined in Exhibit G (IP License) to the Services Agreement) and access to certain Facility IP) in accordance with the requirements of the Services Agreement coupled with either (x) failure to raise a good-faith claim that the Services conform to the Services Agreement or (y) failure, within fifteen (15) days of issuance of a final decision of the Panel concluding that the Services do not conform to the Services Agreement (issued per Article 19 of the Services Agreement), to perform the Services in accordance with such Panel decision; or (b) willful and complete abandonment or non-performance of all of the Services requested by Owners. Notwithstanding the foregoing, if Service Provider fails or ceases to perform only a portion of the Services (i.e., Service Provider fails or ceases to perform a particular type or category of Service which Service Provider agreed to perform in the Services Agreement, but continues to perform other Services), such failure or cessation shall be deemed a Triggering Event only as to the type or category of Services which Service Provider failed or ceased to perform, and Owners' right to receive a copy of the then-existing Facility IP, Service Provider's obligation to transfer a copy of the Facility IP, and Owners' ability to exercise and enforce the license in and to the then-existing Facility IP shall only apply to that portion of the Facility IP applicable to and associated with the type or category of Service which Service Provider fails or ceases to provide, in order to fully enable Owners to self-perform or have a Third Party perform the Services without any support or technical assistance from Service Provider.

(f) "Use" means to access, use, copy, reproduce, modify, prepare derivative works, make, have made (including export and import in compliance with applicable US law), distribute, perform and display for Facility Purposes and in compliance with the provisions of this Facility IP License.

2. **Grant of License**.

(a) Service Provider hereby grants, agrees to grant, and shall cause to be granted to Owners, and their Affiliates, and employees of Affiliates, effective as of the Effective Date and exercisable solely in accordance with Section 3 below, a royalty-free, fully paid-up, non-exclusive, transferable (solely in connection with any sale or transfer of the Facility), irrevocable and perpetual license, all subject to Section 10, under, in and to the Facility IP (as the same may exist at the time of a Triggering Event or later issue as a patent based on a patent application filed prior to the Triggering Event), to Use, and permit Third Parties to Use (all solely in accordance with Section 6 below), the Facility and all equipment, components, hardware, software and other deliverables, and the Facility IP (as the same may exist at the time of the Triggering Event or later issued as a patent based on a patent application filed prior to the Triggering Event), solely as necessary for Owners to design, construct, test, startup, license, complete, maintain, improve, and operate the Facility, and to complete and defend challenges on ITAAC or respond to other requests made by any Government Authority or pursuant to applicable Law, in all such cases without Service Provider's support or technical assistance. Owners shall have the right to sublicense to Third Parties (subject to Section 6 below) the rights conferred upon Owners, provided that such sublicenses shall be limited to Use solely on Owners' behalf and solely in connection with the Facility Purposes. The license rights granted by Service Provider to Owners pursuant to this Facility IP License do not include any rights in and to any

Facility IP other than as specifically set forth in this Facility IP License, and do not include any right to use any Facility IP (i) with or for any facility other than the Facility (Vogtle Units 3 & 4), or (ii) for the manufacture or design of fuel assemblies for AP1000 ® reactors. The licenses granted herein are in addition to and not in lieu of any other licenses granted under the Services Agreement or other agreements between the Parties or between Service Provider and Owners. The restrictions set forth in this Facility IP License apply only to the license granted in this Facility IP License.

(b) The license granted by Service Provider to Owners hereunder shall not prejudice the rights of Service Provider (or its Affiliates) to sell or license all or any portion of the Facility IP to others, or to use the Facility IP on an unfettered basis, shall not obligate Service Provider in any way to provide updates or improvements made to the Facility IP transferred to Owners after the date of the Triggering Event, and shall not obligate Service Provider in any way to file for or maintain intellectual property protections for any Service Provider intellectual property, including Facility IP (Owners are free to request Service Provider to pursue intellectual property protections for such Service Provider intellectual property at Owners' expense), provided that the sale or license of any Facility IP by Service Provider or its Affiliates shall be subject to and not free and clear of this Facility IP License or any other licenses granted to Owners by Service Provider or otherwise adversely affect this Facility IP License Agreement including, without limitation, pursuant to section 363 of the Bankruptcy Code or other applicable Law.

3 . **Owners' Ability to Exercise and Enforce License Rights** .

(a) Owners acknowledge and agree that, although this Facility IP License is attached to and made a part of the Services Agreement and the license to Facility IP granted by Service Provider pursuant to Section 2 is made effective as of the Effective Date, the rights and licenses granted by Service Provider to Owners hereunder shall not become exercisable or enforceable by Owners, and Owners hereby covenant not to exercise, enforce or use their rights to Facility IP granted pursuant to this Facility IP License, unless and until such time that a Triggering Event occurs and any Service Provider opportunity to cure as described in Section 1.(e) has been exhausted, it being understood that this covenant will not impact any rights that Owners may have under any other license. As such, Service Provider's obligations under this Facility IP License shall not become enforceable by Owners, and Service Provider shall not be obligated by this Facility IP License Agreement to transfer or provide a copy of the Facility IP to Owners by virtue of the requirements of this Facility IP License, unless and until such time that the Triggering Event occurs and any Service Provider opportunity to cure as described in Section 1.(e) has been exhausted.

(b) If the Services Agreement is terminated for convenience by Owners or due to Owners' material breach (pursuant to Section 20.2 of the Services Agreement), the Facility IP license granted to Owners hereunder shall immediately terminate (or, if the Services Agreement is terminated for such reasons before the occurrence of the Triggering Event, shall never become exercisable by Owners); provided, however, that if a Triggering Event has occurred prior to Owners' termination of the Services Agreement for convenience, this Facility IP License shall

not terminate with respect to Owners' license to Facility IP that was the subject of the Triggering Event.

4. **Triggering Event**.

Upon the occurrence of the Triggering Event and if Service Provider is unable to cure as described in Section 1.(e), Service Provider shall be obligated to promptly transfer to Owners a full and complete copy of the then-existing Facility IP in the file format(s) as they exist in Service Provider's and its Affiliates' systems and files, and Owners' license with respect to the then existing Facility IP as described in Section 2 above, shall become immediately exercisable and enforceable by Owners. If Service Provider fails to perform a particular type or category of Services but continues to perform other types or categories of Services, such event will be considered a Triggering Event only as to the category of Service which Service Provider failed to perform. Accordingly, if Service Provider is unable to cure in this instance, Service Provider shall transfer a copy of the portion of the then-existing Facility IP corresponding to that category of Service which led to the Triggering Event and the terms herein shall apply to that licensed portion of Facility IP. Owners' partial exercise of this Facility IP License shall not preclude or prejudice Owners from receiving or exercising any additional partial or full licenses of Facility IP pursuant to Sections 2 and 3 due to any additional Triggering Events.

5. **Assignment**.

(a) Owners shall have the right to, and shall, assign this Facility IP License (including all the rights and obligations hereunder) to any purchaser of the Facility or their successor in connection with their ownership interest in the Facility.

(b) Owners' consent shall not be required for WEC's and WECTEC's assignment of their rights and obligations under this Agreement in connection with an assignment of their rights and obligations under the Services Agreement in connection with the Bankruptcy Cases provided, however, that the rights of Owners under the Bankruptcy Code are preserved in all respects and WEC shall remain a party hereto and obligated hereunder unless the assignee in such a transaction also acquires substantially all of the Facility IP such that Owners' rights under this Facility IP License are not adversely affected.

(c) WEC shall ensure that any assignment, sale or exclusive license of any portion of this Facility IP License is subject to the rights and obligations of Section 2 and the covenant not to sue in Section 7(c) (but only with respect to IP Improvements of such Facility IP made by Owners as of or before such assignment, sale or exclusive license ("Covenant IP Improvements")), and in a manner, by operation of law or otherwise, such that any further assignee, purchaser or exclusive licensee of such Facility IP takes such Facility IP subject to the rights and obligations of Section 2 and the covenant not to sue in Section 7(c) (with respect to Covenant IP Improvements). WEC shall also be entitled to assign to any assignee, purchaser or exclusive licensee of any portion of the Facility IP the right to enforce this Facility IP License against Owners, to the extent it relates to the Use or disclosure of Facility IP. In addition to the foregoing, WEC shall ensure that any assignment, sale, or exclusive license of its interest in and to its Facility IP, or any portion thereof,

pursuant to which WEC divests possession of any portion of the Facility IP or is otherwise rendered unable to satisfy its obligations under Section 4 is subject to the assignee's, purchaser's or exclusive licensee's agreement to be bound by the transfer obligations under Section 4 and the requirements of this sentence of Section 5 . WECTEC shall have the right to, and shall, assign this Facility IP License (including all the rights and obligations hereunder) to any assignee of the Services Agreement in connection with any assignment of such agreement and shall, in connection with any such assignment, ensure that the rights of Owners under the US Bankruptcy Code are preserved in all respects.

(d) Assignment rights for third-party software shall be subject to the terms of the associated third-party software license and may require ratification by the Third Party. Any assignment or transfer in violation of this Facility IP License will be null and void. This Facility IP License and the rights and obligations of either Party hereto will be binding upon and will inure to the benefit of the Parties hereto and their respective successors and permitted assigns, including but not limited to any bankruptcy trustee appointed.

6. Limitations on Sharing of Facility IP .

(a) The right of Owners to share and/or subcontract the Facility IP (pursuant to Section 2), shall be subject to the limitations and conditions set forth in Section 3 with regard to the ability of Owners to exercise their rights in and to the Facility IP.

(b) Owners must keep and maintain all Facility IP provided by Service Provider hereunder and marked "proprietary", "confidential" or the like, as confidential and exercise at least the same degree of care to safeguard the confidentiality of the Facility IP as they do to safeguard their own proprietary or confidential information of equal importance, but not less than a reasonable degree of care, and may only share or disclose the Facility IP as necessary to exercise their rights hereunder, and subject to the following conditions: (i) any permitted sharing or disclosure by Owners of Facility IP shall be made subject to a written agreement which (A) restricts the use and disclosure thereof by the recipient in the same manner as Owners' use and disclosure is restricted, (B) contains confidentiality obligations at least as protective as those contained in this Section 6 , and (C) names Service Provider as a third party beneficiary; (ii) Owners shall be responsible for any breach by such third party recipients of Facility IP of such written agreements of their non-use and non-disclosure obligations with respect to the Facility IP; and (iii) any sharing of Facility IP by Owners shall be limited to only those portions of the Facility IP which are necessary to be shared in order for Owners to exercise their rights under this Facility IP License.

(c) The foregoing obligations of confidentiality in Section 6(b) shall not apply to any sharing or disclosure of Facility IP by Owners which is required by any Government Authority or pursuant to applicable Law (provided, however, Owners shall not disclose Facility IP to the U.S. Patent Office or any other Patent Office or patent authority as part of a patent application) provided that Owners: (i) use reasonable efforts to provide Service Provider with written notice of such request or demand as promptly as practicable under the circumstances so that Service Provider shall have an opportunity to seek an appropriate protective order or other appropriate

remedy; (ii) furnish only that portion of the Facility IP which is, in the opinion of Owners' counsel, legally required; and (iii) take, and cause their representatives to take, all other reasonable steps necessary to try to obtain confidential treatment for any such Facility IP required to be furnished.

(d) Nothing in this Facility IP License or in any disclosures made hereunder shall be construed as granting to Owners the right to file for any intellectual property right (patent, copyright, trademark, etc.) related to or incorporating Facility IP.

7. Ownership of Facility IP and Improvements thereon .

(a) As between Service Provider and Owners, Service Provider shall own all right, title and interest in and to all Intellectual Property associated with the Facility IP provided hereunder.

(b) To the extent Owners create any modifications or derivative works in the Facility IP, Owners shall own all right, title and interest in and to all Intellectual Property associated with such modifications or derivative works. Owners' Use of any such modifications or derivative works is limited to Facility Purposes.

(c) The Parties acknowledge that each Party may independently develop or have developed improvements to or derivative works of the Facility IP (hereinafter "IP Improvements") that may infringe on the other Party's Intellectual Property in its IP Improvements. Each Party intends that such development not block the other Party's development activities, and, consequently: i) Service Provider covenants not to sue Owners, their Affiliates, or any Person authorized by Owners to Use such IP Improvements on Owners' behalf, for infringement or misappropriation of the Service Provider's Intellectual Property in such IP Improvements for Facility Purposes; and ii) Owners covenant not to sue Service Provider, its Affiliates, or any Person authorized by Service Provider to use such IP Improvements on Service Provider's behalf, for infringement or misappropriation of the Owners' Intellectual Property in such IP Improvements.

8 . No Warranty Regarding Sufficiency of Facility IP .

Service Provider represents and warrants that it owns all rights, title and interest in and to the Facility IP (excluding Third-Party IP as provided in Section 10 below) or has the right to license Facility IP to Owners. Service Provider makes no representation whatsoever (and none is to be implied or relied upon by Owners) as to the sufficiency or accuracy of the Facility IP, the ability of Owners to use the Facility IP for its intended purpose, or the results to be obtained from such use, and Service Provider expressly disclaims any and all warranties associated with the Facility IP, including any implied warranty of fitness for a particular purpose or merchantability, and any warranty (express or implied) of title, non-infringement, quality, usefulness, commercial utility, adequacy, compliance with any Law, domestic or foreign. For avoidance of doubt, the Facility IP is provided "as is," and with all faults.

9. No Liability for Use of Facility IP .

Except to the extent Service Provider provides any Facility IP which knowingly infringes any third party Intellectual Property and fails to disclose such infringement prior to Owners' Use thereof (in which case Service Provider shall fully indemnify and hold Owners harmless therefor), Service Provider shall not be liable with respect to or resulting from Owners' use following a Triggering Event, or the results of such use, of any Facility IP licensed to Owners under this Facility IP License, and Owners shall be exclusively responsible and liable for, and shall defend, indemnify and hold harmless Service Provider (and its Affiliates, directors, officers, partners, employees, agents, consultants, contractors, advisors, and other representatives) from, any losses, claims or liability arising out of such use by Owners of Facility IP furnished hereunder or any errors therein or omissions therefrom.

10 . Third Party Licenses .

To the extent any Intellectual Property included in the Facility IP licensed to Owners hereunder is owned by a Third Party and licensed to Service Provider (" Third Party IP "), Service Provider shall identify all such Third Party IP at the time of delivery of the Facility IP and provide Owners with copies of all relevant licenses, if permitted. The license of such Third Party IP to Owners hereunder shall be subject to all of the terms and conditions of the relevant agreement between the applicable Service Provider party and such Third Party pursuant to which such Third Party IP has been licensed to Service Provider, or if elected by Owners, Owners may negotiate new agreements with such third parties for the use of the Third Party IP. For the avoidance of doubt, Service Provider shall have no obligation to grant Owners any license or sublicense rights to any Third Party IP included in the Facility IP if such grant to Owners would result in (i) the violation of any agreement between Service Provider and the applicable Third Party, (ii) the loss or impairment of rights in any Facility IP (including such Third Party IP), or (iii) an obligation to pay royalties on the part of Service Provider or any of its Affiliates (unless, with respect to such Third Party IP subject to an obligation to pay royalties, Owners request such Third Party IP be included in the Facility IP and pay or otherwise reimburse Service Provider or its applicable Affiliates for all such royalties).

11. Termination .

Service Provider may terminate this Facility IP License and the rights and licenses granted to Owners under this Facility IP License with immediate effect upon notice to Owners if Owners commit a material breach of this Facility IP License and fail to cure such breach within thirty (30) days after Service Provider provides written notice of such breach to Owners (or such later period as may be provided in Service Provider's notice). As used in this Section 11, a "material breach" shall mean Owners have exercised the license in Section 2 prior to a Triggering Event, have shared the Facility IP in violation of Section 6 , or have exercised rights in the Facility IP not granted in this Facility IP License, in all such cases resulting in a materially adverse effect on Service Provider. A material breach does not include an exercise of rights to Facility IP granted to Owners under a separate license between the Parties. Except for the foregoing and as set forth in Section 3(b) , this Facility IP License may only otherwise be terminated upon mutual written

agreement by Service Provider and Owners. Except to the extent Facility IP is otherwise licensed to Owners under a separate agreement, upon any termination permitted by this Section 11 , Owners must immediately cease all use of the Facility IP and return all Facility IP to Service Provider (and return or destroy all copies thereof); provided, however, that if Owners' material breach only affects a portion of the Facility IP, then Owners' rights shall only cease with respect to, and Owners shall only be obligated to return, that portion of the Facility IP that is affected by Owners' material breach.

12. Miscellaneous.

(a) Dispute Resolution. In the event of any dispute under this Facility IP License, the Parties shall proceed in accordance with the dispute resolution process set forth in the Services Agreement, *mutatis mutandis* .

(b) Applicable Law . This Facility IP License will be governed by Section 22.1 of the Services Agreement.

(c) Waiver . No Party will be deemed to have waived any provision of this Facility IP License unless such waiver is made explicit in writing and signed by the Party waiving such provision. No waiver will be deemed to be a continuing waiver unless so stated in writing.

(d) Amendment . No change, amendment, or modification of this Facility IP License will be binding upon the Parties unless such change, amendment, or modification is in writing and duly executed by the Parties.

(e) Severability . If any one or more of the provisions in this Facility IP License or any application of such provision is held to be invalid, illegal or unenforceable in any respect by a competent tribunal, the validity, legality and enforceability of the remaining provisions in this Facility IP License and all other applications of the remaining provisions shall not in any way be affected or impaired by such invalidity, illegality or unenforceability.

(f) Entire Agreement . This Facility IP License and the Services Agreement contains the entire agreement of the Parties, and there are no oral or written representations, understandings or agreements between the Parties respecting the subject matter of this Facility IP License that are not expressed herein.

(g) Notice . All notices and other communications hereunder shall be in writing and shall be delivered in accordance with the notice provisions contained in the Services Agreement.

(h) Other Licenses . Nothing in this Facility IP License is intended to reduce Owners' rights to use, or Service Provider's obligations to deliver and provide access to Facility IP in accordance with the requirements of the Services Agreement or any other licenses granted to Owners.

(i) Bankruptcy Code .

(i) The Parties acknowledge and agree that the Facility IP is "intellectual property" as defined in Section 101(35A) of the United States Bankruptcy Code, codified as 11 U.S.C. § 101 et seq. (the "Bankruptcy Code"), that has been licensed hereunder in a contemporaneous exchange for value.

(ii) In the event this Facility IP License is rejected pursuant to applicable law in a case under the Bankruptcy Code, Owners may elect to retain their rights under this Facility IP License as provided in Section 365(n) of the Bankruptcy Code.

(j) Each of the Parties hereby acknowledges the existence, perfection and validity of the Secured Parties' (as defined in the DIP Term Loan Facility defined below) liens on and security interests in the Facility IP as granted and authorized by the (1) Final Order (I) Authorizing Debtors To Obtain Senior Secured, Superpriority, Postpetition Financing (II) Granting Liens and Superpriority Claims Pursuant to Bankruptcy Code Sections 105, 362, 363, 364 and 507, Bankruptcy Rules 2002, 4001, 6004, and 9014 and Local Rule 4001-2 and (III) Granting Related Relief and (2) that certain Guarantee and Collateral Agreement (DIP Term Loan Facility), dated as of May 26, 2017, among the Westinghouse Electric Company LLC, Toshiba Nuclear Energy Holdings (UK) Limited, TSB Nuclear Energy Services Inc., each other Pledgor identified therein and Citibank, N.A. Docket No. 565 entered in the Bankruptcy Cases.

(k) Owners waive (i) any administrative claims allowable under 11 U.S.C. Section 503(b) arising from the performance of the EPC Agreement and (ii) any right of setoff they may have with respect to the EPC Agreement under the Bankruptcy Code or applicable nonbankruptcy law. Facility IP developed under the EPC Agreement is as-is, where-is and without warranty or indemnity.

IN WITNESS WHEREOF, the Parties hereto have executed this Facility IP License as of the Execution Date.

GEORGIA POWER COMPANY, FOR ITSELF AND AS AGENT FOR OGLETHORPE POWER CORPORATION (AN ELECTRIC MEMBERSHIP CORPORATION), MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA, MEAG POWER SPVJ, LLC, MEAG POWER SPVM, LLC, MEAG Power SPVP, LLC and THE CITY OF DALTON, GEORGIA, ACTING BY AND THROUGH ITS BOARD OF WATER, LIGHT, AND SINKING FUND COMMISSIONERS

By: /s/Chris Cummiskey
Name: Chris Cummiskey
Title: Executive Vice President - Georgia Power Company

Attest: /s/Meredith M. Lackey
Its: Senior Vice President, General Counsel & Corporate Secretary

(CORPORATE SEAL)

WECTEC GLOBAL PROJECT SERVICES INC.

By: /s/David C. Durham
Name: David C. Durham
Title: President

Attest: /s/Patricia L. Crown
Its: Notary Public
Patricia L. Crown
(CORPORATE SEAL)

WESTINGHOUSE ELECTRIC COMPANY LLC

By: Jose E. Gurierrez
Name: Jose E. Gurierrez
Title: President and CEO

Attest: /s/Patricia L. Crown
Its: Notary Public
Patricia L. Crown

(CORPORATE SEAL)

EXHIBIT G
IP LICENSE

This IP LICENSE ("IP License") is made as of July 20, 2017 ("Execution Date"), and becomes effective as of the Effective Date as defined in the Amended and Restated Services Agreement, by and between, on the one hand, GEORGIA POWER COMPANY, a Georgia corporation, for itself and as agent for Owners, as defined below, and, on the other hand, WESTINGHOUSE ELECTRIC COMPANY LLC, a Delaware limited liability company having a place of business in Cranberry, Pennsylvania ("WEC"), and WECTEC GLOBAL PROJECT SERVICES INC., a Louisiana corporation having a place of business in Charlotte, North Carolina ("WECTEC" and together with WEC, the "Service Provider"). Owners and Service Provider may be referred to individually as a "Party" and collectively as the "Parties."

1. Definitions. For purposes of this IP License, the terms listed below shall have the meanings indicated beside them. Capitalized terms not otherwise defined below shall have the meanings ascribed to them in the Amended and Restated Services Agreement between Owners and the Service Provider of even date herewith (together with all Exhibits thereto, as amended or modified and as may be further amended or modified from time to time, the "Services Agreement").

(a) "Configuration Data" means the Facility-specific data that is used in conjunction with the software, including without limitation, tuning and set point constants, graphical, pictorial and text files, that instantiate the software for the specific Facility environment.

(b) "Facility IP" means all Intellectual Property (and associated deliverables, products, and other materials described in this definition) of Service Provider or its Affiliates, whether now existing or hereafter developed, in or covering the Facility (including all equipment, components, hardware, software and other deliverables) as delivered under the Services Agreement or under the EPC Agreement (including Intellectual Property, deliverables, products, and materials underlying, supporting, or used to create deliverables under the EPC Agreement or Services Agreement, regardless of whether the same have been or will be provided to Owners, but excluding products delivered by Service Provider's fuels group to Owners under separate commercial agreements), required or reasonably necessary for Owners to design, construct, test, startup, license, complete, maintain, improve, and operate the Facility, to defend challenges on ITAACs or respond to other requests made by any Government Authority or pursuant to applicable Law, including (i) patents, trademarks (but excluding the Westinghouse name or any trademarks related to AP1000 ®), copyrights, trade secrets, inventions, know-how, proprietary information, confidential information, documentation, materials and data; (ii) software required or reasonably necessary for Facility Purposes, including Service Provider (or its Affiliates)-owned and developed proprietary computer programs expressed in a source code language consisting of a full source language statement of programs and all related compiler command files, build scripts, complete maintenance documentation, application programming interfaces, graphical user

interfaces, schematic diagrams and annotations which comprise the pre-coding detail design specifications, information management data bases (e.g., open item database, PCC outstanding issues list, DCP database, LAR database, ITAAC database), plans, designs, calculations and models (e.g., seismic models, structural models, stress analyses, hazards analyses – flooding, PRHA, probabilistic risk assessment, etc.), design basis information, computer source code for CYS monitoring system and all CYS design documents, cyber security databases (e.g., CDA identification database, LRM assessment database, cyber SharePoint site, etc.) and all cyber security supporting documentation, simulator designs; (iii) all AP1000 ® -related schematics, designs and information, included but not limited to AP1000 ® information referenced in the DCD or COL; and (iv) all other information, documentation, materials, data, technology, software and other property necessary to allow a reasonably skilled person to design, construct, test, license, startup, operate, improve, complete and maintain the Facility.

(c) “Intellectual Property” means any and all intellectual property rights existing from time to time under any Law including patent law, copyright law, semiconductor chip protection law, moral rights law, trade secret law, trademark law (together with all goodwill associated therewith (but excluding any rights to the Westinghouse name or any trademarks related to AP1000 ®)), unfair competition law, publicity rights law, or privacy rights law, and any and all other proprietary rights, and any and all applications, renewals, extensions and restorations of any of the foregoing, now or hereafter in force and effect worldwide. For purposes of this definition, rights under patent laws shall be limited to rights under any and all United States patent applications (and patents issued therefrom) and patents (including letters patent and inventor’s certificates), including, without limitation, any provisionals, substitutions, extensions, supplementary patent certificates, reissues, renewals, divisions, continuations in part (or in whole), continued prosecution applications, requests for continued examination, and other similar filings or stages thereof provided for under the laws of the United States.

(d) “Licensed Documentation” shall mean that portion of the Licensed IP that includes any (i) materials created by or on behalf of Service Provider or its licensors, or by Third Parties, that describe or relate to the functional, operational, or performance capabilities of any Licensed IP regardless of whether such materials be in written, printed, electronic or other format; and (ii) user, operator, system administration, technical, support and other manuals, including but not limited to functional specifications, help files, flow charts, logic diagrams, programming comments, and acceptance plans, if any.

(e) “Licensed IP” means (i) that portion of the Facility IP delivered by Service Provider to Owners, or to which Owners are given access by Service Provider pursuant to the Services Agreement (the types of Licensed IP that will be delivered to Owners are identified in Exhibit B of the Services Agreement); (ii) that portion of the Facility IP delivered by Service Provider to Owners under the EPC Agreement; and (iii) any Intellectual Property that is not capable of being delivered (e.g., patent rights) but is required to enable Owners’ Use of Facility equipment, components, hardware, and software delivered under the EPC Agreement or the Services Agreement.

(f) “Owners” means Georgia Power Company, Oglethorpe Power Corporation (An Electric Membership Corporation), Municipal Electric Authority of Georgia, MEAG Power

SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners.

(g) "Permitted Users" means Owners, their employees, and the employees of their Affiliates, when they are acting as agent for the Owners. Permitted Users shall also include (i) Owners' engineers, seconded employees and staff augmentation contractors, where acting as agent for Owners, through multiple tiers, engaged by Owners, and (ii) Facility contractors and subcontractors engaged by Owners for work in connection with the Facility, in each case subject to the requirements of Article 14 of the Services Agreement.

(h) "Software" or "software" means any computer programming code (such as computer programs, procedures, rules or routines embodied in computer programs, databases and related computer files) consisting of instructions or statements in a form readable by individuals (source code) or machines (object code) and related documentation and supporting materials therefor, in any form or medium, including electronic media. Software includes any bug fixes, error-correction releases, updates, upgrades, enhancements, modifications, changes, new versions and replacements therefor.

(i) "Service Provider Software" means the Software provided to Owners by Service Provider or Service Provider's Affiliates or licensors through Service Provider, in connection with the Services performed under the Services Agreement or work performed under the EPC Agreement that is required or reasonably necessary for Facility Purposes. Software includes:

(i) " *base software* ", which consists of the programs and tools that provide basic Facility system functions. The base software may include tools used to develop control strategies (function blocks, standard control algorithms, rules, etc.), operator graphics (e.g., symbol libraries), and database entries;

(ii) " *application software* ", which consists of the project-specific implementation of the Facility requirements using the objects and tools provided by the base software. The application software is specific to a particular Facility; and

(iii) " *third-party software* ", which consists of that portion of the software which is developed and owned by a Third Party. Third-party software may include freeware.

(j) "Use" means to access, use, copy, reproduce, modify, prepare derivative works, make, have made (including export and import in compliance with applicable US law), distribute, perform, and display for Facility Purposes and in compliance with the provisions of this IP License.

2. Licenses.

(a) License. Service Provider hereby grants, agrees to grant, and shall cause to be granted to Owners and their Affiliates, a perpetual, irrevocable, fully paid-up, royalty-free, non-exclusive, transferable (solely in connection with any sale or transfer of the Facility) right and license under, in and to the Facility IP, to Use the Facility and all equipment, components,

hardware, software and other deliverables as such are delivered or made available to Owners, including Service Provider Software, and in each case, solely for Facility Purposes. Owners shall have the right to sublicense to Permitted Users the rights conferred upon Owners, provided that such sublicenses shall be limited to Use solely on Owners' behalf and solely for Facility Purposes. Third-party software which is furnished by Service Provider shall be subject to separate license agreements and/or registration requirements and limitations on copying and use, and Owners agree to be bound by the terms of any such license agreements to the extent Owners have been provided a copy of the same or as may be negotiated between Owners and each third-party software provider. The license rights granted by Service Provider to Owners pursuant to this IP License do not include any rights in and to any Facility IP other than as specifically set forth in this IP License, and do not include any right to use any Facility IP (i) with or for any facility other than the Facility (Vogtle Units 3 & 4), or (ii) for the manufacture or design of fuel assemblies for AP1000 reactors.

(b) Service Provider shall provide all third-party software on a pass-through basis as further described herein. Notwithstanding anything to the contrary herein, and without limiting the license above, the license granted herein grants and shall grant Owners and the Permitted Users the rights to:

(i) Use the Licensed IP for the Facility Purposes;

(ii) adapt and otherwise modify the Licensed IP, including but not limited to the Service Provider's base software and application software;

(iii) make a reasonable number of copies of the Service Provider Software for back-up, archival, testing, installation, maintenance, operation or disaster-recovery purposes, provided that any copyright or other proprietary rights notices included in the Service Provider Software are also reproduced in such copies. The right to copy specific third-party software shall be governed by terms of the license agreement specific to such third-party software provided to Owners;

(iv) install the Service Provider Software on replacement hardware and adapt and modify the Service Provider Software to be used on other hardware, provided that the Service Provider Software as installed on such hardware is solely used for the Facility Purposes. The right to install specific third-party software as described in this subsection (iv) shall be governed by terms of the license agreement specific to such third-party software provided to Owners;

(v) make the Licensed IP accessible to, or otherwise disclose Licensed IP, to the Nuclear Regulatory Commission and other Government Authorities as required or requested for Facility Purposes subject to Section 6.3 of the Services Agreement; and

(vi) Use and disclose, subject to Article 14 of the Services Agreement, the output and other information derived from the Licensed IP (whether such Licensed IP is deliverable or only accessible) in support of the Facility Purposes and as otherwise required to comply with applicable Laws or requirements of requests from Government Authorities.

(c) License Restrictions. Except as may be otherwise provided herein, Owners shall not alone or with the assistance of others use any Licensed IP other than for the Facility Purposes. Except for the licenses granted herein or as otherwise provided in the Services Agreement, all right, title, and interest in the Licensed IP shall remain with Service Provider or its licensors.

(d) Licensed Documentation Reproduction and Distribution. Service Provider hereby grants, agrees to grant, and shall cause to be granted to Owners a perpetual, irrevocable, transferrable (solely in connection with any sale or transfer of the Facility), fully paid-up, royalty-free, non-exclusive right and license to modify and create derivative works, reproduce and distribute to Permitted Users Licensed Documentation solely for the Facility Purposes. Rights and obligations regarding the modification, reproduction and distribution of third-party software documents shall be as set forth in the applicable third-party software license. Rights and obligations regarding the modification, reproduction and distribution of any other third party documents included in Licensed Documentation shall be as specified by the owners of the third party documents.

(e) Other Computer Programs. Nothing shall prohibit the Permitted Users from using the Facility equipment to run computer programs other than the software or from using the equipment for purposes other than operation of the Facility, it being understood that Service Provider shall not be responsible for any failure of the software or equipment as a result of such activities, or loading such computer programs on, or removing such computer programs from, the Facility equipment.

3. Representations and Warranties. Service Provider represents and warrants the following **:**

(a) Licensing Rights. Service Provider owns all rights, title and interest in and to the Licensed IP (excluding third-party software, third-party software documentation or any other third party information or materials provided under the Services Agreement) or otherwise has the legal right to transfer, grant, sublicense, or, for third-party software, pass-through the rights and the licenses in the foregoing that are provided herein. In the event of a breach of this warranty, Service Provider shall obtain, at no additional cost to Owners, rights necessary for Owners to continue using the Licensed IP as contemplated by this IP License. For pass-through rights, third-party software and associated documentation shall be licensed directly from the third-party software developer to Owners as end user, and copies of all such licenses shall be provided to Owners. To the best of Service Provider's knowledge, the Licensed IP is true, accurate and complete and represents all of the intellectual property to be provided to Owners under the Services Agreement, at the applicable time.

(b) Media. The media on which the Licensed IP, including but not limited to software, is recorded shall be free from defects in material and workmanship for the Warranty Period set forth in (d) below. Service Provider will, at no additional charge, replace any defective media.

(c) Intellectual Property . Licensed IP and Licensed Documentation will not knowingly infringe, misappropriate, or otherwise violate any patent, trademark, service mark, copyright, trade secret or other proprietary right of any Third Party.

(d) Performance. The Licensed IP, including but not limited to the software and Configuration Data shall be treated in accordance with Article 10 of the Services Agreement *mutatis mutandis* ; provided, however, that Facility IP developed under the EPC Agreement shall be provided on an as-is, where-is basis and without warranty. In addition to re-performance under Article 10 of the Services Agreement (to the extent required thereby), Service Provider agrees to use commercially reasonable efforts during the term of the Services Agreement and subject to the terms and conditions therein, at Owners' request and expense, to provide updates, corrections, replacements, repairs, and other work to ensure that Facility software, hardware, Configuration Data, or other physical deliverables meet Owners' needs.

4. Intellectual Property Indemnity.

(a) Service Provider shall indemnify, hold harmless, release and defend Owner Persons Indemnified from any action brought against Owners, their Affiliates or any of their respective Representatives, to the extent based on a claim that any Licensed IP or any part thereof furnished hereunder, or the use thereof as permitted under this IP License, constitutes an infringement of any United States patent or United States copyright, or misappropriation of any trade secret, trademark rights, proprietary rights or other intellectual property rights of any Third Party; provided, however, Owners shall promptly notify Service Provider of any such claim, suits and actions in writing and Service Provider shall pay all costs, expenses, settlements and/or judgments resulting therefrom.

(b) If a claim of infringement or misappropriation is made, Service Provider may, and if the use of the Licensed IP developed by Service Provider or any part thereof furnished hereunder is held by a court of competent jurisdiction to constitute infringement or misappropriation of any United States copyright, trade secret, trademark rights, proprietary rights or other intellectual property rights of any Third Party, and its use by Owners is enjoined, Service Provider shall, at its option and its sole expense, either: (i) procure for Owners the right to continue using said Licensed IP, or part thereof; or (ii) replace or modify the same with non-infringing Licensed IP, to the extent reasonably possible without diminishing the capability and capacity of the Licensed IP, or part thereof. In the event the above alternatives are unavailable to Service Provider, then, with the approval of Owners, Service Provider shall seek alternate ways and means to provide such Services for which it is obligated under this Agreement so long as such alternate means are reasonably acceptable to Owners.

(c) Notwithstanding the above, Service Provider shall not compromise or settle any claim, action, suit or proceeding in which Owners are named without Owners' prior written consent, which consent shall not be unreasonably conditioned, delayed or withheld unless such settlement provides for the payment of money only by Service Provider and provides for a full, complete and unconditional (other than ceasing use of the applicable Licensed IP) release of Owners and each Permitted User.

(d) The foregoing indemnity shall not apply in situations where the Licensed IP is: (i) supplied pursuant to a design or drawing prepared by Owners wherein Service Provider has deviated from its normal course of performance; (ii) modified or combined by Owners or otherwise with items not furnished hereunder; or (iii) outside the scope of the Licensed Documentation and without the Service Provider's approval or consent. In the event a suit or proceeding is brought against Service Provider as a result of such Owners' actions, Owners will indemnify and save Service Provider harmless to the same extent as Service Provider has agreed to indemnify and save Owners harmless hereunder, except that the limitation of liability provision of Section 17.2 of the Services Agreement shall not apply.

(e) This Section 4 is an exclusive statement relating to intellectual property indemnification regarding the Licensed IP. In no event shall Owners be entitled to duplicative recovery under this Section 4 and Section 16.4 of the Services Agreement.

(f) Any indemnities associated with third-party software shall be governed by the terms of the license agreements associated with such third-party software. Where the third-party software is directly licensed to Owners by Third Parties, Service Provider shall have no obligation to indemnify Owners for any claims of infringement related to the use by Owner of such third-party software.

(g) Service Provider's liability under this Section 4 shall be subject to the limitation of liability provision of Section 17.2 of the Services Agreement.

5. **Assignment.**

(a) Owners shall have the right to, and shall, assign this IP License (including all the rights and obligations hereunder) to any purchaser of the Facility or their successor in connection with their ownership interest in the Facility.

(b) Owners' consent shall not be required for WEC's and WECTEC's assignment of their rights and obligations under this IP License in connection with an assignment of their rights and obligations under the Services Agreement in connection with the Bankruptcy Cases provided, however, that the rights of Owners under the Bankruptcy Code are preserved in all respects and WEC shall remain a party hereto and obligated hereunder unless the assignee in such a transaction also acquires substantially all of the Facility IP such that Owners' rights under this IP License are not adversely affected.

(c) WEC shall ensure that any assignment, sale or exclusive license of any portion of the Facility IP is subject to the rights and obligations of Section 2 and the covenant not to sue in Section 6(c) (but only with respect to IP Improvements of such Facility IP made by Owners as of or before such assignment, sale or exclusive license ("Covenant IP Improvements")), and in a manner, by operation of law or otherwise, such that any further assignee, purchaser or exclusive licensee of such Facility IP takes such Facility IP subject to the rights and obligations of Section 2 and the covenant not to sue in Section 6(c) (with respect to Covenant IP Improvements). WEC shall also be entitled to assign to any assignee, purchaser or exclusive licensee of any portion of the Facility IP the right to enforce this IP License against Owners, to the extent it relates to the

Use or disclosure of Facility IP. In addition to the foregoing, WEC shall ensure that any assignment, sale, or exclusive license of its interest in and to its Facility IP, or any portion thereof, pursuant to which WEC divests possession of any portion of the Facility IP or is otherwise rendered unable to satisfy its obligations under Section 4 is subject to the assignee's, purchaser's or exclusive licensee's agreement to be bound by the requirements of this sentence of Section 5. WECTEC shall have the right to, and shall, assign this IP License (including all the rights and obligations hereunder) to any assignee of the Services Agreement in connection with any assignment of such agreement and shall, in connection with any such assignment, ensure that the rights of Owners under the US Bankruptcy Code are preserved in all respects.

(d) Assignment rights for third-party software shall be subject to the terms of the associated third-party software license and may require ratification by the Third Party. Any assignment or transfer in violation of this IP License will be null and void. This IP License and the rights and obligations of either Party hereto will be binding upon and will inure to the benefit of the Parties hereto and their respective successors and permitted assigns, including but not limited to any bankruptcy trustee appointed.

6. **Ownership of Licensed IP and Improvements thereon.**

(a) As between Service Provider and Owners, Service Provider shall own all right, title and interest in and to all Intellectual Property associated with the Licensed IP provided hereunder.

(b) To the extent Owners create any modifications or derivative works in the Licensed IP, Owners shall own all right, title and interest in and to all Intellectual Property associated with such modifications or derivative works. Owners' Use of any such modifications or derivative works is limited to Facility Purposes.

(c) The Parties acknowledge that each Party may independently develop or have developed improvements to or derivative works of the Licensed IP (hereinafter "IP Improvements") that may infringe on the other Party's Intellectual Property in its IP Improvements. Each Party intends that such development not block the other Party's development activities, and, consequently: i) Service Provider covenants not to sue Owners, their Affiliates, or any Person authorized by Owners to Use such IP Improvements on Owners' behalf, for infringement or misappropriation of the Service Provider's Intellectual Property in such IP Improvements for Facility Purposes; and ii) Owners covenant not to sue Service Provider, its Affiliates, or any Person authorized by Service Provider to use such IP Improvements on Service Provider's behalf, for infringement or misappropriation of the Owners' Intellectual Property in such IP Improvements.

7. **Miscellaneous.**

(a) Dispute Resolution. In the event of any dispute under this IP License, the Parties shall proceed in accordance with the dispute resolution process set forth in the Services Agreement, *mutatis mutandis* .

(b) Term. This IP License shall commence on the Effective Date and shall be coterminous with the Services Agreement; provided, upon any termination of this IP License, the perpetual licenses granted hereunder shall continue without interruption, and Sections 1, 4, 5, and 6 shall survive any such termination or expiration.

(c) Applicable Law. This IP License will be governed by Section 22.1 of the Services Agreement.

(d) Waiver. No Party will be deemed to have waived any provision of this IP License unless such waiver is made explicit in writing and signed by the Party waiving such provision. No waiver will be deemed to be a continuing waiver unless so stated in writing.

(e) Amendment. No change, amendment, or modification of this IP License will be binding upon the Parties unless such change, amendment, or modification is in writing and duly executed by the Parties.

(f) Severability. If any one or more of the provisions in this IP License or any application of such provision is held to be invalid, illegal or unenforceable in any respect by a competent tribunal, the validity, legality and enforceability of the remaining provisions in this IP License and all other applications of the remaining provisions shall not in any way be affected or impaired by such invalidity, illegality or unenforceability.

(g) Entire Agreement. This IP License and the Services Agreement contain the entire agreement of the Parties, and there are no oral or written representations, understandings or agreements between the Parties respecting the subject matter of this IP License that are not expressed herein.

(h) Notice. All notices and other communications hereunder shall be in writing and shall be delivered in accordance with the notice provisions contained in the Services Agreement.

(i) Other Licenses. Nothing in this IP License is intended reduce or expand Owners' rights under any other licenses granted to Owners, except that the licenses granted hereunder supersede and replace any licenses granted under the EPC Agreement.

(j) Bankruptcy Code.

(i) The Parties acknowledge and agree that the Licensed IP is "intellectual property" as defined in Section 101(35A) of the United States Bankruptcy Code, codified as 11 U.S.C. § 101 et seq. (the "Bankruptcy Code"), that has been licensed hereunder in a contemporaneous exchange for value.

(ii) In the event this IP License is rejected pursuant to applicable law in a case under the Bankruptcy Code, Owners may elect to retain their rights under this IP License as provided in Section 365(n) of the Bankruptcy Code.

(k) Each of the Parties hereby acknowledges the existence, perfection and validity of the Secured Parties' (as defined in the DIP Term Loan Facility defined below) liens on and

security interests in the Facility IP as granted and authorized by the (1) Final Order (I) Authorizing Debtors To Obtain Senior Secured, Superpriority, Postpetition Financing (II) Granting Liens and Superpriority Claims Pursuant to Bankruptcy Code Sections 105, 362, 363, 364 and 507, Bankruptcy Rules 2002, 4001, 6004, and 9014 and Local Rule 4001-2 and (III) Granting Related Relief and (2) that certain Guarantee and Collateral Agreement (DIP Term Loan Facility), dated as of May 26, 2017, among the Westinghouse Electric Company LLC, Toshiba Nuclear Energy Holdings (UK) Limited, TSB Nuclear Energy Services Inc., each other Pledgor identified therein and Citibank, N.A., Docket No. 565 entered in the Bankruptcy Cases.

(l) Owners waive (i) any administrative claims allowable under 11 U.S.C. Section 503(b) arising from the performance of the EPC Agreement and (ii) any right of setoff they may have with respect to the EPC Agreement under the Bankruptcy Code or applicable nonbankruptcy law. Facility IP developed under the EPC Agreement is as-is, where-is and without warranty or indemnity.

IN WITNESS WHEREOF, the Parties hereto have executed this IP License as of the Execution Date.

GEORGIA POWER COMPANY, FOR ITSELF AND AS AGENT FOR OGLETHORPE POWER CORPORATION (AN ELECTRIC MEMBERSHIP CORPORATION), MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA, MEAG POWER SPVJ, LLC, MEAG POWER SPVM, LLC, MEAG Power SPVP, LLC and THE CITY OF DALTON, GEORGIA, ACTING BY AND THROUGH ITS BOARD OF WATER, LIGHT, AND SINKING FUND COMMISSIONERS

By: /s/Chris Cummiskey
Name: Chris Cummiskey
Title: Executive Vice President - Georgia Power Company

Attest: /s/Meredith M. Lackey
Its: Senior Vice President, General Counsel & Corporate Secretary

(CORPORATE SEAL)

WECTEC GLOBAL PROJECT SERVICES INC.

By: /s/David C. Durham
Name: David C. Durham
Title: President

Attest: /s/Patricia L. Crown
Its: Notary Public
Patricia L. Crown
(CORPORATE SEAL)

WESTINGHOUSE ELECTRIC COMPANY LLC

By: Jose E. Gurierrez
Name: Jose E. Gurierrez
Title: President and CEO

Attest: /s/Patricia L. Crown
Its: Notary Public
Patricia L. Crown

(CORPORATE SEAL)

EXHIBIT H
SUBCONTRACTS AND PURCHASE ORDERS

A. Service Provider shall assume and assign to Owners or their designee, and Owners or their designee shall accept assignment of, the subcontracts and purchase orders listed below.

	Purchase Order/ Subcontract	SAP PO	Debtor	SubContractor/Vendor	Contract Description/Title
1	132175F001086	WSPM004620	Stone & Webster Construction Inc	A&W OIL CO INC	Change Order to add Funding to PO 747595 for Lubricants for $25,000
2	132175F004697	WSPM009914	Stone & Webster Construction Inc	A&W OIL CO INC	PM Temp.Const.SG2565 Mobilux EP2 SG165 Multifak EP2,SG 564 XH 222,SG034 DTE24,SG034 DTE25,SG2427 DTELight,SG2382 ChevSRI
3	WVG3001455	WVG3001455	WECTEC Global Project Services, Inc.	A&W OIL CO INC	Mobilube HD Plus 85W-140 for Maintenance of the 220 ton Crane TI3
4	WVG3001314	WVG3001314	WECTEC Global Project Services, Inc.	A&W OIL CO INC	Grease for Turbine Island 3 220 Ton & 15 Ton Crane for PM to Start Up
5	132175F006084	WSPM004724	WECTEC Global Project Services, Inc.	AAA SIGN COMPANY INC	Electronic Sign Repair
6	132175F002381-A	WSPM004994	Stone & Webster Construction Inc	ABB ENTERPRISE SOFTWARE INC	VENTYX eSOMS Software
7	132175-EP01.01	WSPM015467	Stone & Webster Construction Inc	ABB INC	Turbine Generator Synchronization Control Panel
8	132176-EP01.01	WSPM015303	Stone & Webster Construction Inc	ABB INC	Turbine Generator Synchronization Control Panel
9	132175-C215.04	WSPM010031	Stone & Webster Construction Inc	AC CONTROLS CO INC	Butterfly Valves|
10	132176-C203.01	WSPM010032	Stone & Webster Construction Inc	AC CONTROLS CO INC	Threaded and Socket Weld Carbon Steel Valves|
11	132176-C215.01	WSPM010033	Stone & Webster Construction Inc	AC CONTROLS CO INC	Butterfly Valves|
12	J132175-C215.03	WSPM009810	Stone & Webster Construction Inc	AC CONTROLS CO INC	Valves|

13	WVG3000470	WVG3000470	WECTEC Global Project Services, Inc.	AC CONTROLS CO INC	Material to be left in place and used for building 315 for RWS, work package SV0-RWS-PLW-ME0917
14	132175-C203.03	WSPM010030	Stone & Webster Construction Inc	AC CONTROLS CO INC	Threaded and Socket Weld Carbon Steel Valves |
15	WVG3001549	WVG3001549	WECTEC Global Project Services, Inc.	ACE INDUSTRIES INC	MAB Overhead Cranes Quarterly Inspection /
16	132175-E032.01	WSPM003359	WECTEC Global Project Services, Inc.	ADVANCED CABLE BUS INC	600V Cable Bus System
17	132175-C811.02	WSPM010831	Stone & Webster Construction Inc	ADVANCED PRODUCTS AND SYSTEMS	Dielectric Gaskets for CWS
18	J132175-J800.03	WSPM013367	Stone & Webster Construction Inc	AGGREGATES USA LLC	Aggregates
19	132175F000882	WSPM004632	Stone & Webster Construction Inc	AGGREKO LLC	Replacement Chiller for Batch Plant
20	132175F004441	WSPM010663	Stone & Webster Construction Inc	AH HARRIS AND SONS INC	Construction Aid Material Nonpermanent Plant. For Use By Iron Workers NI3.
21	J132175-FPR12-02618	WSPM010292	Stone & Webster Construction Inc	AH HARRIS AND SONS INC	Concrete surface Nuclear Island 3 Basemat pour.
22	WVG3000189	WVG3000189	Stone & Webster Construction Inc	AH HARRIS AND SONS INC	Temporary Construction Aid for BOP Carpenters
23	132175F005164	WSPM005013	WECTEC Global Project Services, Inc.	AIKEN TECHNICAL COLLEGE	Rental Space for 16 hours for Offsite Transition Meeting January 27th and 29th 2016
24	132175F000365	WSPM014774	Stone & Webster Construction Inc	AIR LIQUIDE INDUSTRIALS US LP	Batch Plant - Add Funds PO 759556-3P - Air Liquide
30	132175F005863	WSPM010198	WECTEC Global Project Services, Inc.	AIRGAS INC	Respirator Fit Test for HSE Field Testing
31	WVG3001009	WVG3001009	WECTEC Global Project Services, Inc.	AIRGAS INC	Industrial Hygiene - Airgas Order
35	WVG3000680	WVG3000680	WECTEC Global Project Services, Inc.	AIRGAS NATIONAL WELDERS	HSE - Industrial Hygiene Supplies for site wide use
36	132175F005891	WSPM010208	WECTEC Global Project Services, Inc.	AIRGAS USA LLC	MSA Replacement Sensors - Environmental Use
37	WVG3000539	WVG3000539	WECTEC Global Project Services, Inc.	AIRGAS USA LLC	Special Ferrules for Welding to Vertical Surfaces
38	132175F000041-2	WSPM010524	Stone & Webster Construction Inc	AIRWAYS FREIGHT CORPORATION	Airways Freight to provide door to door pick up and delivery 365 x 24
39	J132175-FPR13-02070	WSPM002109	Stone & Webster Construction Inc	AL PATTERSON INC	To Install the precast panels in the Auxiliary Building

40	132175F000373	WSPM004653	Stone & Webster Construction Inc	ALERE TOXICOLOGY SERVICE INC	Change Attachment , FFD Special requirements for drug testing per NRC Regulations, to PO 681033-000 OP, Alere Toxicology Services, Inc
41	132175F000148	WSPM012396	Stone & Webster Construction Inc	ALLTEC LIFTING SYSTEMS LLC	Change Order to PO 849833 (Alltec Lifting Systems) 12 months extention on Rental
42	132175F001547	WSPM004667	Stone & Webster Construction Inc	ALLTEC LIFTING SYSTEMS LLC	Add additonal Funds to Alltec, PO 752386 on Lifting Beam and Plates
43	132175F002026	WSPM004436	Stone & Webster Construction Inc	ALLTEC LIFTING SYSTEMS LLC	Change Order to Extend Rental on Alltec Modular Lifting beam PO 745575 for 12 months
44	132175F003041	WSPM004469	Stone & Webster Construction Inc	ALLTEC LIFTING SYSTEMS LLC	CO to extend rental to Alltec Lifting Systems PO # 868741 for 12 months
45	132175000828 REL 007	WSPM013354	Stone & Webster Construction Inc	ALUMA PANEL OF SC INC	BLANKET ORDER TRANSFER 831033 3P
46	132175F000828 REL 005	WSPM004641	Stone & Webster Construction Inc	ALUMA PANEL OF SC INC	BLANKET ORDER REL 005
47	132175F000828 REL 006	WSPM004642	Stone & Webster Construction Inc	ALUMA PANEL OF SC INC	BLANKET ORDER TRANSFER 831033 3P
48	132175F000828 REL 007	WSPM004643	Stone & Webster Construction Inc	ALUMA PANEL OF SC INC	N_6241203 - N_6241203-N/ACNN/A - Banner
49	132175F000828 REL 010	WSPM010364	Stone & Webster Construction Inc	ALUMA PANEL OF SC INC	BLANKET RELEASE
50	132175F000828 REL 012	WSPM004644	Stone & Webster Construction Inc	ALUMA PANEL OF SC INC	BLANKET ORDER RELEASE 012
51	132175F000828 REL 016	WSPM004645	Stone & Webster Construction Inc	ALUMA PANEL OF SC INC	BLANKET ORDER TRANSFER 831033 3P
52	132175F000828 REL 018	WSPM013395	WECTEC Global Project Services, Inc.	ALUMA PANEL OF SC INC	BLANKET ORDER RELEASE 018
53	132175F000828 REL 019	WSPM013394	WECTEC Global Project Services, Inc.	ALUMA PANEL OF SC INC	BLANKET ORDER RELEASE 019
54	132175F000828 REL 020	WSPM013393	WECTEC Global Project Services, Inc.	ALUMA PANEL OF SC INC	BLANKET ORDER TRANSFER 831033 3P
55	132175-C910.15	WSPM003468	Stone & Webster Construction Inc	AMERICAN PLASTIC PIPE AND SUPPLY LL	Corrugated HDPE Pipe
56	132175-C910.17	WSPM003467	Stone & Webster Construction Inc	AMERICAN PLASTIC PIPE AND SUPPLY LL	CWS, PWS, RWS, SDS, WWS, and YFS HDPE Piping and Fittings
57	132175-C910.19	WSPM010631	Stone & Webster Construction Inc	AMERICAN PLASTIC PIPE AND SUPPLY LL	HDPE Pipe and Fittings for U/G WLS

58	J132175-C910-05	WSPM002184	Stone & Webster Construction Inc	AMERICAN PLASTIC PIPE AND SUPPLY LL	HDPE Pipe and Fittings|
59	J132175-C910-07	WSPM002183	Stone & Webster Construction Inc	AMERICAN PLASTIC PIPE AND SUPPLY LL	HDPE PIPE
60	132175F004845	WSPM009887	WECTEC Global Project Services, Inc.	AMERICAN STAINLESS & SUPPLY	Temporary Construction Aid - NI4
61	132176-C913.07	WSPM003758	WECTEC Global Project Services, Inc.	AMERICAN STAINLESS & SUPPLY	Fiberglass Piping and Spider Supports for DOS
62	WVG3000788	WVG3000788	WECTEC Global Project Services, Inc.	AMERICAN STAINLESS & SUPPLY	To be used for building bulkheads and bracing formwork
63	WVG3001320	WVG3001320	WECTEC Global Project Services, Inc.	AMERICAN STAINLESS & SUPPLY	SS PLATE 4'X8'X1/8" THICK for CWS Pumps
64	WVG3001425	WVG3001425	WECTEC Global Project Services, Inc.	AMERICAN STAINLESS & SUPPLY	temporary construction aid material to be used for fabrication shops-NOI-6 TI-3 LP Turbine Building overhead crane test frame
65	WVG3001434	WVG3001434	WECTEC Global Project Services, Inc.	AMERICAN STAINLESS & SUPPLY	Temporary construction aide material to be used to ensure anchorage shall not move for Unit 4 Turbine, work package SV4-2060-C0W-850000
66	WVG3001459	WVG3001459	WECTEC Global Project Services, Inc.	AMERICAN STAINLESS & SUPPLY	BOP TEMPORARY CONSTRUCTION AID MATERIAL FOR TEST HEADER
67	WVG3001478	WVG3001478	WECTEC Global Project Services, Inc.	AMERICAN STAINLESS & SUPPLY	CA37 Temporary Bracing
68	WVG4001245	WVG4001245	WECTEC Global Project Services, Inc.	AMERICAN STAINLESS & SUPPLY	Material to be left in place and used for fabrication of spring element plates for Unit 4 Turbine CA81 tabletop, work package SV4-2050-SSW-CV1823
69	WVG4001251	WVG4001251	WECTEC Global Project Services, Inc.	AMERICAN STAINLESS & SUPPLY	Material to be left in place and used for fabrication of beams (borrowed from Unit 3) and lateral bracing for Unit 4 Turbine CA81 tabletop, SV4-2050-SSW-CV1823
70	WVG4001253	WVG4001253	WECTEC Global Project Services, Inc.	AMERICAN STAINLESS & SUPPLY	Material to be left in place and used for fabrication of beams (borrowed from Unit 3) and lateral bracing for Unit 4 Turbine CA81 tabletop, SV4-2050-SSW-CV1823

71	132175-E102.03	WSPM005021	Stone & Webster Construction Inc	ANIXTER INC	Medium Voltage Power Cable
72	132175-EW82.01	WSPM001939	WECTEC Global Project Services, Inc.	ANIXTER INC	Non-Class 1E Fiber Optic Cable Connectors
73	132176-EW82.01	WSPM001263	WECTEC Global Project Services, Inc.	ANIXTER INC	Non-Class 1E Fiber Optic Cable Connectors
74	132175-G120.00	WSPM010363	Stone & Webster Construction Inc	APPLIED TECHNICAL SERVICES INC	Testing for Pressure Sensitive Tape
75	132175-J800.19	WSPM004550	Stone & Webster Construction Inc	APPLIED TECHNICAL SERVICES INC	Testing Of A490 Bolt From Unit 4 Turbine Building
76	132175-J800.22	WSPM004551	WECTEC Global Project Services, Inc.	APPLIED TECHNICAL SERVICES INC	Charpy V-notch Testing
77	879098-3P	WSPM004958	Stone & Webster Construction Inc	APPLIED TECHNICAL SERVICES INC	Additional Funding for PO 879098 for analysis for ATS swipe test PO. Additional funds will be added to cover future samples and the outstanding balance, total amount to be $37,000.00
78	WVG3000269	WVG3000269	Stone & Webster Construction Inc	APPLIED TECHNICAL SERVICES INC	Requisition for NDE services to be performed by ATS. Magnetic particle examination of closure nuts
79	WVG3000310	WVG3000310	WECTEC Global Project Services, Inc.	APPLIED TECHNICAL SERVICES INC	Add Funds ($150,000.00) to existing PO 866115
80	132175-MY50.00	WSPM003927	Stone & Webster Construction Inc	ARMSTRONG HUNT INC	Hot Water Unit Heaters and Duct Mounted Heating Coils
81	132176-MY50.00	WSPM003044	Stone & Webster Construction Inc	ARMSTRONG HUNT INC	Hot Water Unit Heaters and Duct Mounted Heating Coils
82	132175F000060-A	WSPM010689	Stone & Webster Construction Inc	ASCENDUM MACHINERY INC	Consumables For Equipment Example Bucket Cutting Edge
83	132175F002920	WSPM004412	Stone & Webster Construction Inc	ASCENDUM MACHINERY INC	Change Order to Extend Rental on PO 842430 From ASC Construction Equipment on Crawler Excavator for 12 months
84	132175F003088	WSPM004466	Stone & Webster Construction Inc	ASCENDUM MACHINERY INC	ASC VOLVO TO REPLACE MONITOR IN 480 EXCAVATOR DUE TO OPERATOR DAMAGE
85	4500714381	4500714381	WECTEC Contractors Inc	ASCENDUM MACHINERY INC	PARTS
86	4500715367	4500715367	WECTEC Contractors Inc	ASCENDUM MACHINERY INC	Parts Inv# P215045455

87	4500715709	4500715709	WECTEC Global Project Services, Inc.	ASCENDUM MACHINERY INC	Equipment Repair Parts and Service
88	4500715755	4500715755	WECTEC Contractors Inc	ASCENDUM MACHINERY INC	PARTS
89	4500715789	4500715789	WECTEC Global Project Services, Inc.	ASCENDUM MACHINERY INC	Equipment Repair Parts and Service
90	4500715790	4500715790	WECTEC Global Project Services, Inc.	ASCENDUM MACHINERY INC	Equipment Repair Parts and Service
91	4500716072	4500716072	WECTEC Global Project Services, Inc.	ASCENDUM MACHINERY INC	Equipment Repair Parts and Service
92	4500716463	4500716463	WECTEC Global Project Services, Inc.	ASCENDUM MACHINERY INC	Equipment Repair Parts and Service
93	4500716520	4500716520	WECTEC Global Project Services, Inc.	ASCENDUM MACHINERY INC	Equipment Repair Parts and Service
94	4500716521	4500716521	WECTEC Contractors Inc	ASCENDUM MACHINERY INC	Parts Inv# S215018628
95	4500716522	4500716522	WECTEC Contractors Inc	ASCENDUM MACHINERY INC	Parts Inv# P215044857
96	4500716524	4500716524	WECTEC Contractors Inc	ASCENDUM MACHINERY INC	Parts Inv# P215044856
97	4500716591	4500716591	WECTEC Contractors Inc	ASCENDUM MACHINERY INC	PARTS
98	4500717358	4500717358	WECTEC Global Project Services, Inc.	ASCENDUM MACHINERY INC	Equipment Repair Parts and Service
99	4500717828	4500717828	WECTEC Global Project Services, Inc.	ASCENDUM MACHINERY INC	Equipment Repair Parts and Service
100	4500336244	4500336244	Westinghouse Electric Company LLC	ASCO	Three Way Compressed Air Solenoid Valves
101	132175F001876	WSPM004449	Stone & Webster Construction Inc	ASHLEY SLING INC	330198 Liebherr Crane Boom Hoist Cable
102	132175F003818	WSPM014122	Stone & Webster Construction Inc	ASHLEY SLING INC	UNIT# 330177 Liebherr Crane Boom Hoist Cable
103	132175F003836	WSPM014101	Stone & Webster Construction Inc	ASHLEY SLING INC	Splice and Rope For Use By Electricians In Nuclear Island 3.
104	WVG3000406	WVG3000406	Stone & Webster Construction Inc	ASHLEY SLING INC	TRANSFER OF FUNDS FROM 715426-3P
105	WVG3001132	WVG3001132	WECTEC Global Project Services, Inc.	ASHLEY SLING INC	1-1/4” x 4-1/2” HR125 SWIVEL HOIST RING 1016975 8000-240902
106	WVG3001103	WVG3001103	WECTEC Global Project Services, Inc.	ATCO STRUCTURES & LOGISTICS USA INC	to be used at fabrication shops in NOI-6 for buildings 4 ,5, 6 roofs

107	132175F003529	WSPM010419	Stone & Webster Construction Inc	ATLANTIC SUPPLY AND EQUIP CO INC	Temporary Construction - BOP
108	WVG3000927	WVG3000927	Stone & Webster Construction Inc	ATLAS VAN LINES INC	Transportation Service
109	WVG3000023	WVG3000023	WECTEC Global Project Services, Inc.	AUGUSTA COMMUNICATION	PM Check for Site Radio Network
110	WVG3000414	WSPM011030	WECTEC Global Project Services, Inc.	AUGUSTA COMMUNICATION	TRANSFER OF FUNDS FROM 967463-3P
111	132175-AM01.00	WSPM003325	WECTEC Global Project Services, Inc.	AUGUSTA CONCRETE BLOCK CO	Non-Safety Related Unit 3 Annex Building Masonry Walls
112	132175F002149A	WSPM004433	Stone & Webster Construction Inc	AUGUSTA ENGINE PARTS INC	N_SVC-ENGREPAIR - N_SVC-ENGREPAIR-N/ACNN
113	WVG3001427	WVG3001427	WECTEC Global Project Services, Inc.	AUGUSTA OVERHEAD DOOR SALES INC	TO BE LEFT IN PLACE AND USED FOR OVERHEAD DOOR AUXILIARY OUTPUT EXPANSION MODULE FOR GARAGE DOORS AT BLDG 315
114	630207-OP	WSPM004294	Stone & Webster Construction Inc	AUTOMATIC FIRE SYSTEMS AUGUSTA	Automatic Fire Systems
115	WVG3000600	WVG3000600	WECTEC Global Project Services, Inc.	AUTOMATIC FIRE SYSTEMS AUGUSTA	TEST AND INSPECTION SERVICE - 630207 TRANS
116	132175-G200A-01	WSPM003207	Stone & Webster Construction Inc	AVANTECH INC	FOB Jobsite (7828 River Road
117	620740	WSPM004297	Stone & Webster Construction Inc	B LAMAR MURRAY MD	Vogtle EPC-Unit 3 & Site
118	4500714190	4500714190	WECTEC Contractors Inc	B&M EQUIPMENT REPAIR AND CERTFCTN	Spare Parts
119	4500721297	4500721297	WECTEC Global Project Services, Inc.	B&M EQUIPMENT REPAIR AND CERTFCTN	Equipment Repair Parts and Service
120	4500721415	4500721415	WECTEC Global Project Services, Inc.	B&M EQUIPMENT REPAIR AND CERTFCTN	Equipment Repair Parts and Service
121	4500721417	4500721417	WECTEC Global Project Services, Inc.	B&M EQUIPMENT REPAIR AND CERTFCTN	Equipment Repair Parts and Service
122	4500696355	4500696355	Westinghouse Electric Company LLC	BARNHART CRANE & RIGGING CO	Jacking Hunches Load Test
123	4500714565	4500714565	WECTEC Contractors Inc	BASIS SOFTWARE INC	DAMAGE ASSESSMENT AND TESTING OF SN730
124	4500715840	4500715840	WECTEC Contractors Inc	BASIS SOFTWARE INC	PARTS
125	4500675306	4500675306	Westinghouse Electric Company LLC	BCP TECHNICAL SERVICES INC	Travel & Living

126	132175F002376	WSPM010238	Stone & Webster Construction Inc	BEASLEY FOREST PRODUCTS INC	Crane Mats for Site Support
127	132175F003292	WSPM010408	Stone & Webster Construction Inc	BEASLEY FOREST PRODUCTS INC	36 - 4’x1’x20’ oak crane mats for site support.
128	132175F003533	WSPM010425	Stone & Webster Construction Inc	BEASLEY FOREST PRODUCTS INC	8ea 1’x4’x8’ crane mats for MAB Up ender and 7ea 1’x4’x20’ crane mats for site support
129	132175F004249	WSPM015404	Stone & Webster Construction Inc	BEASLEY FOREST PRODUCTS INC	Crane Mats for site support, Ron Lewis. 9x5x5 = 4, 12x4x20 = 60.
130	132175F004638	WSPM004922	Stone & Webster Construction Inc	BEASLEY FOREST PRODUCTS INC	40 - 30’ Crane Mats, Site Support Ron Lewis.
131	132175F006023	WSPM010107	WECTEC Global Project Services, Inc.	BEASLEY FOREST PRODUCTS INC	Wood saddle to be used for temporary support of the MSR A/B at the MSR temporary staging area.
132	132175F000371	WSPM015492	Stone & Webster Construction Inc	BEST OFFICE SOLUTIONS LLC	Work Package/Blueprint Storage for MAB Documentum Office
134	132175F002428	WSPM004393	Stone & Webster Construction Inc	BEST OFFICE SOLUTIONS LLC	Office Supplies
135	132175F002721	WSPM010086	Stone & Webster Construction Inc	BEST OFFICE SOLUTIONS LLC	OSD&D TAGS
136	132175F003161	WSPM015457	Stone & Webster Construction Inc	BEST OFFICE SOLUTIONS LLC	Stud Weld Pre-Production Qualification Record (SWPPQR) Form
137	132175F003645	WSPM010275	Stone & Webster Construction Inc	BEST OFFICE SOLUTIONS LLC	GREEN ACCEPT TAGS
138	WSV3B00037	WSV3B00037	WECTEC Global Project Services, Inc.	BEST OFFICE SOLUTIONS LLC	Site copy paper/NTE $250,000.00 in 1 year
139	WVG3000038	WVG3000038	WECTEC Global Project Services, Inc.	BEST OFFICE SOLUTIONS LLC	Site Copy Paper/NTE - F000999-REL017
140	WVG3001061 - REL 020	WVG3001061	WECTEC Global Project Services, Inc.	BEST OFFICE SOLUTIONS LLC	Site Copy Paper/NTE $ 250,000.00 in 1 Year from APR 2016
141	WVG3001349	WVG3001349	WECTEC Global Project Services, Inc.	BEST OFFICE SOLUTIONS LLC	Site Copy Paper/NTE $ 250,000.00 in 1 Year
142	132175F001482	WSPM004601	Stone & Webster Construction Inc	BIG RED INC	Change Order to Extend Rental 24 months on T550RR Forklift, Big Red, Unit # 34307
143	132175F002053	WSPM004434	Stone & Webster Construction Inc	BIG RED INC	TAYLOR - BIG RED 360 FOR ADDITIONAL OPERATOR
144	132175F003281	WSPM004512	Stone & Webster Construction Inc	BIG RED INC	Rev 1 to PO 839969 extending rental on Big Red unit # 37958, XC350L forklift for 12 months

145	132175F004253	WSPM004870	Stone & Webster Construction Inc	BIG RED INC	Exchange Taylor Big Red TX-300 for a Taylor Big Red TX-350, Doug Smiths group.
146	132175F004791	WSPM009908	Stone & Webster Construction Inc	BIG RED INC	Taylor Big Red Forklift Forks Failed Inspection
147	132175F004984	WSPM004924	WECTEC Global Project Services, Inc.	BIG RED INC	REPLACE PO 888927, Big Red extending rent 2 years on unit # 38115.
148	132175F001312	WSPM004608	Stone & Webster Construction Inc	BIG TOP MANUFACTURING INC	TENT END WALLS
149	132175F001521	WSPM009844	Stone & Webster Construction Inc	BIG TOP MANUFACTURING INC	Removable Shelters for CA20 in NI3
150	132175F002814	WSPM004420	Stone & Webster Construction Inc	BIG TOP MANUFACTURING INC	Big Top Tent Assembly *URGENT*
151	132175F003882	WSPM015505	Stone & Webster Construction Inc	BIG TOP MANUFACTURING INC	BIG TOP TENT THAT WILL BE USED TO STORE TRANSFORMER PARTS
152	132175F004109	WSPM003342	Stone & Webster Construction Inc	BIG TOP MANUFACTURING INC	Tents to be used for the pipe spool storage
153	132175F005682	WSPM004885	WECTEC Global Project Services, Inc.	BIG TOP MANUFACTURING INC	Replacement Parts for disappearing door on Big Top Tent at NOI-7
154	WVG3000564	WVG3000564	Stone & Webster Construction Inc	BIG TOP MANUFACTURING INC	Tent material to be used for level B storage for laydown areas
155	132175F001827	WSPM004453	Stone & Webster Construction Inc	BIGGE POWER CONSTRUCTORS	330198 LIEBHERR CRANE ENGINE PROBLEMS
156	132175F002544	WSPM004505	Stone & Webster Construction Inc	BIGGE POWER CONSTRUCTORS	330177 LIEBHERR CRANE MONITOR REPAIR
157	132175F003550	WSPM004459	Stone & Webster Construction Inc	BROWNS OFFICE CENTRE	Furniture for New Buildings
158	132175F004668	WSPM004843	Stone & Webster Construction Inc	BROWNS OFFICE CENTRE	Building 303 Cubical and Desk
159	132175F005112	WSPM004832	WECTEC Global Project Services, Inc.	BROWNS OFFICE CENTRE	Security Orientation Cards and Camera Cards
160	WVG3000266	WVG3000266	Stone & Webster Construction Inc	BROWNS OFFICE CENTRE	88 L Shaped Cubicles for field engineers, quality control inspectors, welding engineers, and design engineers.
161	WVG3000320	WVG3000320	Stone & Webster Construction Inc	BROWNS OFFICE CENTRE	Tables & Chairs
162	WVG3000380	WVG3000380	Stone & Webster Construction Inc	BROWNS OFFICE CENTRE	Elect Fab & Facilities

163	WVG3000518	WVG3000518	Stone & Webster Construction Inc	BROWNS OFFICE CENTRE	Microwave & Refrig for 207, ASB, & Replacements
164	WVG3000542	WVG3000542	Stone & Webster Construction Inc	BROWNS OFFICE CENTRE	Furniture for Bldg 124
165	132175F003665	WSPM004463	Stone & Webster Construction Inc	C B EQUIPMENT INC	TRUCKS FOR WAREHOUSE USE
166	132175F004534	WSPM004815	Stone & Webster Construction Inc	C B EQUIPMENT INC	Trailer to replace unit # 67693.
167	132175F004698	WSPM004915	Stone & Webster Construction Inc	C B EQUIPMENT INC	Trailers for Site Support. 2 years rent.
168	132175F005070	WSPM004821	WECTEC Global Project Services, Inc.	C B EQUIPMENT INC	flatbed trailers for warehouse use issuing
169	132175F005313	WSPM004942	WECTEC Global Project Services, Inc.	C B EQUIPMENT INC	Warehouse deliveries
170	WVG3000718	WSPM007277	WECTEC Global Project Services, Inc.	C B EQUIPMENT INC	Three Refer Trailers to Conduct Ice and Water Distribution
171	132175F000108	WSPM010692	Stone & Webster Construction Inc	CARDIAC SCIENCE	Annual AED Service
172	132175F004127	WSPM004877	Stone & Webster Construction Inc	CAROL CRANE RIGGING AND	CO to PO 888352 Carol Crane Rigging, for steel crane mats. $2000 needed to cover rent thru 30 Aug 15, units will then be removed from rent.
173	132175-C203.04	WSPM015395	Stone & Webster Construction Inc	CAROTEK INC	Remaining Site Specific Valves
174	132175-C205.01	WSPM010287	Stone & Webster Construction Inc	CAROTEK INC	Check Valves for CWS
175	132175-PV53.00	WSPM000109	WECTEC Global Project Services, Inc.	CAROTEK INC	PV53-Plumbing and Specialty Valves for various NSR applications
176	132176-PV53.00	WSPM003035	WECTEC Global Project Services, Inc.	CAROTEK INC	PV53-Plumbing and Specialty Valves for various NSR applications
177	WVG3000948	WVG3000948	WECTEC Global Project Services, Inc.	CAROTEK INC	Material to be left in place and used for building 315, work package SV0-RWS-PLW-ME0917
178	132175F000855	WSPM014765	Stone & Webster Construction Inc	CARRIER COMMERCIAL SERVICE	Batch Plant - Blanket PO for Carrier Commercial Services
179	WVG3001260	WVG3001260	WECTEC Global Project Services, Inc.	CAVCO INC	To be left in place and used for bldg 315, Permanent Potable Water System Chem Add Skid (SV0-PWS-MS-501), work package SV0-PWS-01-CT001

180	132175F005787	WSPM004914	WECTEC Global Project Services, Inc.	CDW DIRECT	CISCO - IT Supplies (est. $125k)
181	132175-D100.15	WSPM013149	Stone & Webster Construction Inc	CHATHAM STEEL CORP	ZRS Pipe Support Material Building 315
182	132175-D220.17	WSPM010495	Stone & Webster Construction Inc	CHATHAM STEEL CORP	Embed Plate Material
183	132175-D500.05 REL 1	WSPM011849	Stone & Webster Construction Inc	CHATHAM STEEL CORP	Non-Safety Structural Steel
184	132175-D500.05-REL-008	WSPM010623	Stone & Webster Construction Inc	CHATHAM STEEL CORP	BLANKET RELEASE 008 STRUCTURAL STEEL
185	132175-D500.05-REL-014	WSPM010123	WECTEC Global Project Services, Inc.	CHATHAM STEEL CORP	BLANKET RELEASE 014 STRUCTURAL STEEL
186	132175-D500.05-REL-019	WSPM003454	WECTEC Global Project Services, Inc.	CHATHAM STEEL CORP	BLANKET RELEASE 019 STRUCTURAL STEEL
187	132175-D500.05-REL-020	WSPM000047	WECTEC Global Project Services, Inc.	CHATHAM STEEL CORP	BLANKET RELEASE 020 STRUCTURAL STEEL
188	132175-D500.05-REL-022	WSPM000046	WECTEC Global Project Services, Inc.	CHATHAM STEEL CORP	BLANKET RELEASE 022 STRUCTURAL STEEL
189	132175-D500.11	WSPM003378	Stone & Webster Construction Inc	CHATHAM STEEL CORP	Structural Steel Non-Safety Related
190	132175-D500.17	WSPM011641	Stone & Webster Construction Inc	CHATHAM STEEL CORP	Non-Safety Shims, Plates, and Hilti Anchors
191	132175-D500.20	WSPM001216	Stone & Webster Construction Inc	CHATHAM STEEL CORP	Bearing Plates For Viscodampers In Turbine Building
192	132175F002560	WSPM014097	Stone & Webster Construction Inc	CHATHAM STEEL CORP	TEMPORARY CONSTRUCTION - New Weld Test Shop Steel
193	132175F002905-REL-009	WSPM011542	WECTEC Global Project Services, Inc.	CHATHAM STEEL CORP	REL- 009 for Non-Safety Related Non-Safety
194	132175F002905-REL-011	WSPM001913	WECTEC Global Project Services, Inc.	CHATHAM STEEL CORP	REL-011 for Non-Safety Related
195	132175F004345	WSPM010656	Stone & Webster Construction Inc	CHATHAM STEEL CORP	Material Contamination Prevention during CA02 & CA20 Module Fit-up
196	132175F004486	WSPM004817	Stone & Webster Construction Inc	CHATHAM STEEL CORP	Shims to be used for equipment installation
197	132175F004557	WSPM004839	Stone & Webster	CHATHAM STEEL CORP	Construction aid material to be used for temporary use

			Construction Inc		for the CA20 Platen modification, work package SV0-8200-MHW-CV7385

198	132175F005456	WSPM004933	WECTEC Global Project Services, Inc.	CHATHAM STEEL CORP	Pipe to be used for spreader beams for CA03 installation
199	132176-D500.26	WSPM010410	Stone & Webster Construction Inc	CHATHAM STEEL CORP	Damper Bearing Plates for Box Beams - Unit 4 - Turbine Building
200	J132175-FPR12-02522	WSPM010298	Stone & Webster Construction Inc	CHATHAM STEEL CORP	Temp. constuction materials #4 condensers
201	J132175-FPR13-00751	WSPM004375	Stone & Webster Construction Inc	CHATHAM STEEL CORP	Lifting/Rigging - Spreader bar pipe for miscellaneous lifts
202	J132176-FPR124-00016	WSPM010416	Stone & Webster Construction Inc	CHATHAM STEEL CORP	U4 Turbine Building Construction Aid Material
203	J132176-FPR134-00028	WSPM010265	Stone & Webster Construction Inc	CHATHAM STEEL CORP	Unit 4 Nuclear Island Permanent Construction Aids for Basemat
204	WVG3000183	WVG3000183	Stone & Webster Construction Inc	CHATHAM STEEL CORP	spreader pipe to be used for heavy lifts across site
205	WVG3000777	WVG3000777	WECTEC Global Project Services, Inc.	CHATHAM STEEL CORP	to be used on the unit 3-Initial Energization Temp Air for heating battery rooms
206	J132175-E101.01	WSPM009755	Stone & Webster Construction Inc	CHLORIDE INDUSTRIAL SYSTEMS	Double Throw Switch|
207	132175F001257	WSPM004611	Stone & Webster Construction Inc	CINTAS CORP	Add Funding to Cintas Blanket PO #700123 not to exceed $240,000 or 3 years
208	808831-3P	WSPM004360	Stone & Webster Construction Inc	CINTAS CORP	Add Funding to Blanket PO 808831 Cintas Tobacco Rd Not to Exceed $15,000.00 or 3 years.
209	854472-3P	WSPM004364	Stone & Webster Construction Inc	CINTAS CORP	Add Funding to Cintas Shredding PO 854472 not to Exceed $50,000 or 2 yrs
210	132175F002537	WSPM004507	Stone & Webster Construction Inc	CIT RAIL LLC	Extend Rental 12 months on PO-924069 Cit Rail (Progress Rail)
211	132175F004644	WSPM004841	WECTEC Global Project Services, Inc.	CMI	Est. Blanket PO for CMI, INC - not to exceed $4,000 or 3 years to pay Invoice 813383 and future Invoices
212	132175-J300.19-REL11	WSPM008629	WECTEC Global Project Services, Inc.	COASTAL CONSTRUCTION PRODUCTSINC	Release # 11 Xypex Admix C-500 NF
213	132175-J300.19-REL12	WSPM010855	WECTEC Global Project Services, Inc.	COASTAL CONSTRUCTION PRODUCTSINC	Release # 12 Xypex Patch N Plug (60 lb pails) SG:1705
214	132175F000833	WSPM004424	Stone & Webster Construction Inc	COCA COLA BOTTLING CO UNITED E	bottled water for craft

215	132175F002211	WSPM004430	Stone & Webster Construction Inc	COCA COLA BOTTLING CO UNITED E	Add Funding to PO 741021 Not to Exceed $150,000.00 or 2 yrs
216	WVG3000498	WVG3000498	WECTEC Global Project Services, Inc.	COCA COLA BOTTLING CO UNITED E	BOTTLED WATER
217	WVG3001094	WVG3001094	Stone & Webster Construction Inc	COCA COLA BOTTLING CO UNITED E	NTE Funding for Coke Cola for $75,000.00 or 3 months
218	132175F004562	WSPM004838	Stone & Webster Construction Inc	COMMAND ALKON	Batch Plant - Add funds to PO# 813458; Command Alkon.
219	132175F004100	WSPM010655	Stone & Webster Construction Inc	CONCRETE PUMP SUPPLY	2 - Shut off valve kits for boom tips, concrete pump trucks Robert Carr. 24 months rental.
220	WVG3000420	WVG3000420	WECTEC Global Project Services, Inc.	CONGER-ELSEA INC	CONSULTING SERVICES - CONGER & ELSEA INC
221	132175F003122	WSPM010062	Stone & Webster Construction Inc	CONSOLIDATED PIPE AND SUPPLY CO INC	McElroy Fusion Welder Certification
222	132175F004672	WSPM004844	Stone & Webster Construction Inc	CONSOLIDATED PIPE AND SUPPLY CO INC	Temporay Construction - McElroy Training Fittings
223	132175F004712	WSPM010608	Stone & Webster Construction Inc	CONSOLIDATED PIPE AND SUPPLY CO INC	Temporary construction aid -bulk material to be used as attachments for temporary lift frames, platen modification, and other functions in the MAB
224	WVG3001286	WVG3001286	WECTEC Global Project Services, Inc.	CONSOLIDATED PIPE AND SUPPLY CO INC	Returning EF Fusion Machines for Calibrations Contact Jacob Matthes From Consolidated Pipe & Supply
225	132176-C121.07	WSPM003833	Stone & Webster Construction Inc	CONSOLIDATED POWER SUPPLY	CAS and PGS System Underground Yard Pipe and Fittings Phase 6, 7, and 9
226	J132175-FPR12-02136	WSPM002173	Stone & Webster Construction Inc	CONSOLIDATED POWER SUPPLY	Construction Aids for U3 Containment Vessel Bottom Head
227	J132176-FPR124-00032	WSPM002098	Stone & Webster Construction Inc	CONSOLIDATED POWER SUPPLY	Construction Aids - U4 Nuclear Island Basemat, Mechanical
228	WSV3B00039	WSV3B00039	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	B31.1 Gaskets Safety Class D RTNSS - Blanket Order
229	WVG3000591	WVG3000591	Stone & Webster Construction Inc	CONSOLIDATED POWER SUPPLY	ADDITONAL NON-PERMANENT -NON SAFETY MATERIAL FOR TURBINE #3 FIRE PROTECTION SYSTEM
230	WVG3001016	WVG3001016	Stone & Webster Construction Inc	CONSOLIDATED POWER SUPPLY	Nonpermanent Plant. Construction Aid Material. For Use In Nuclear Island 4.

231	WVG3001029	WVG3001029	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	material to be left in place and used for cable tray welded supports, work package SV3-2053-SHW-861955
232	WVG3001285	WVG3001285	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	I Beams for PM Labeling Conex Redi Roof to be Finished
233	WVG4001244	WVG4001244	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	Material Left in Place Annex 4. Angle Iron due to E&DCR APP-SS01-GEF-850151
234	132175-C121.06	WSPM003279	Stone & Webster Construction Inc	CONSOLIDATED POWER SUPPLY	CAS and PGS System Underground Yard Pipe and Fittings Phase 4 & 5
235	132175-C125.04	WSPM010056	Stone & Webster Construction Inc	CONSOLIDATED POWER SUPPLY	Stainless Steel Laterals for WRS and WLS
236	132175-C812.00A REL 11	WSPM004581	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	B31.1 Gaskets Safety Class D RTNSS - Blanket Order
237	132175-C812.00A REL 8	WSPM004580	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	B31.1 Gaskets Safety Class D RTNSS - Blanket Order
238	132175-C812.00A REL 9	WSPM004579	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	B31.1 Gaskets Safety Class D RTNSS - Blanket Order
239	132175-C812.00A RELEASE 1	WSPM004578	Stone & Webster Construction Inc	CONSOLIDATED POWER SUPPLY	B31.1 Gaskets Safety Class D RTNSS - Blanket Order
240	132175-C812.00A RELEASE 2	WSPM004577	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	B31.1 Bolts Safety Class D-RTNSS - Blanket Order
241	132175-C812.00A RELEASE 3	WSPM004576	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	B31.1 Gaskets Safety Class D RTNSS - Blanket Order
242	132175-C812.00A RELEASE 5	WSPM004592	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	DDP Jobsite (7828 River Road
243	132175-C812.00A RELEASE 7	WSPM004593	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	XAAABAAPAK - I18644270 - Gasket, CL 150
244	132175-D100.11	WSPM003451	Stone & Webster Construction Inc	CONSOLIDATED POWER SUPPLY	CA Module Material
245	132175-D500.18	WSPM003375	Stone & Webster Construction Inc	CONSOLIDATED POWER SUPPLY	Structural Steel for CA20 Module
246	132175-D500.30	WSPM003374	Stone & Webster Construction Inc	CONSOLIDATED POWER SUPPLY	Caps For Detector Well Assemblies In CA04 & Pipe Sleeve For CA01
247	132175F000212	WSPM010529	Stone & Webster Construction Inc	CONSOLIDATED POWER SUPPLY	Consumables for Training and Qualifying Remote Machine Welders
248	132175F000633	WSPM010592	Stone & Webster Construction Inc	CONSOLIDATED POWER SUPPLY	SONOTUBES AND PIPES

249	132175F001056	WSPM003290	Stone & Webster Construction Inc	CONSOLIDATED POWER SUPPLY	Fabrication of rebar trusses to support top mat reinforcement Work Package Number SV3-4030-CCW-CV2187
250	132175F003614	WSPM010437	Stone & Webster Construction Inc	CONSOLIDATED POWER SUPPLY	Non-permanent Fire Protection system for unit 3. Non-safety material.
251	132175F003833	WSPM010333	Stone & Webster Construction Inc	CONSOLIDATED POWER SUPPLY	Temporary Construction Aid Material for CA20-71, 72, 73 & CA20-22B, 25 Assembly Bracing
252	132175F004964	WSPM013667	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	Construction Aid Material For Use In Nuclear Island 3 Steel Fab Shop.
253	132175F005456A	WSPM004947	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	Pipe to be used for spreader beams for CA03
254	132175F005552	WSPM004934	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	Material for Weld Test Shop (Nightshift MAB Weld Testing)
255	132176-D500.45	WSPM009752	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	Structural Steel For Unit 4 Mechanical Modules
256	WVG3000429	WVG3000429	WECTEC Global Project Services, Inc.	CONSTRUCTION EQUIPMENT PARTS INC	Batch Plant Consumables
257	WVG3000848	WVG3000848	WECTEC Global Project Services, Inc.	CONSTRUCTION EQUIPMENT PARTS INC	Batch Plant Materials
258	WVG3001108	WVG3001108	WECTEC Global Project Services, Inc.	CONSTRUCTION EQUIPMENT PARTS INC	Lubricator and Boot Gum Rubber
259	132175F000569-A	WSPM010583	Stone & Webster Construction Inc	CONTINENTAL MFG CO INC	Batch Plant - Parts for Trucks
260	132175F001011-B	WSPM009986	Stone & Webster Construction Inc	CONTINENTAL MFG CO INC	Batch Plant - Flapper Valves and Springs
261	132175F002100	WSPM010168	Stone & Webster Construction Inc	CONTINENTAL MFG CO INC	Batch Plant - Mixer Truck Parts
262	132175F002133	WSPM010174	Stone & Webster Construction Inc	CONTINENTAL MFG CO INC	Batch Plant - Switches for trucks
263	132175F002316	WSPM010114	Stone & Webster Construction Inc	CONTINENTAL MFG CO INC	Batch Plant - Relief valves for truck water tanks
264	132175F002361	WSPM004396	Stone & Webster Construction Inc	CONTINENTAL MFG CO INC	Batch Plant - Lights, Fold Back Chute, and Ball Joint for trucks
265	132175F002425	WSPM010241	Stone & Webster Construction Inc	CONTINENTAL MFG CO INC	Batch Plant - Rollers for trucks
266	132175F002449	WSPM010250	Stone & Webster Construction Inc	CONTINENTAL MFG CO INC	Batch Plant - Reverse lights and chutes for trucks
267	132175F002580	WSPM010193	Stone & Webster Construction Inc	CONTINENTAL MFG CO INC	Batch Plant - Decals, pump, and gaskets for turcks

CONFIDENTIAL& PROPRIETARY
CONFIDENTIAL TRADE SECRET INFORMATION

268	132175F002999-002-REL	WSPM010421	Stone & Webster Construction Inc	CONTINENTAL MFG CO INC	Batch Plant - Continental
269	132175F002999-006-REL	WSPM004472	WECTEC Global Project Services, Inc.	CONTINENTAL MFG CO INC	Batch Plant - Continental (To Establish Blanket PO)
270	132175F003233	WSPM004510	Stone & Webster Construction Inc	CONTINENTAL MFG CO INC	Batch Plant - Emergency Unloading Kit
271	132175F004885	WSPM009913	Stone & Webster Construction Inc	CONTINENTAL MFG CO INC	Batch Plant - truck lights
272	132175F005382	WSPM009727	WECTEC Global Project Services, Inc.	CONTINENTAL MFG CO INC	Batch Plant Order Control Cables
273	WVG3000230	WVG3000230	Stone & Webster Construction Inc	CONTINENTAL MFG CO INC	BO 2999 - Rel 11 Batch Plant - Continental
274	132175F003746	WSPM010336	Stone & Webster Construction Inc	CRAIGS CONSTRUCTION SPECIALTIES INC	Rebar chairs for support in Containment Vessel NI3.
275	132175F000521	WSPM013401	Stone & Webster Construction Inc	CRANE INSTITUTE OF AMERICA INC	Certified Mobile Crane Inspector Training On-Site for June 24th-27th
276	132175F001805	WSPM004456	Stone & Webster Construction Inc	CRUISE SECURITY SYSTEMS INC	Add Funding to existing PO607592 for Cruise Security Systems, Inc.
277	132175-V170.01	WSPM003906	Stone & Webster Construction Inc	CUMMINS INC	Non-Class 1E 480V Standby Diesel Generator
278	132175F001636	WSPM009779	Stone & Webster Construction Inc	DELTA RIGGING AND TOOLS INC	For use for the CA01 sub-modules
279	132175F003211	WSPM010620	Stone & Webster Construction Inc	DELTA RIGGING AND TOOLS INC	General handling equipment for the entire site
280	132175F006036	WSPM010012	WECTEC Global Project Services, Inc.	DELTA RIGGING AND TOOLS INC	Hoist - Chain 10Ton w/ 20' Load & 30' Pull Chain
281	WVG3000014	WVG3000014	WECTEC Global Project Services, Inc.	DELTA RIGGING AND TOOLS INC	10 TON CHAIN FALLS FOR RIGGING
282	WVG3001162	WVG3001162	WECTEC Global Project Services, Inc.	DELTA RIGGING AND TOOLS INC	HOIST EQUIPMENT FOR CWS PUMPS
283	132175F003626	WSPM010640	Stone & Webster Construction Inc	DILLON SUPPLY CO	Constrution aid material to be used in the ZFS Ductbank, Work Package SV0-ZFS-ERW-EL5909
284	132175F003653	WSPM010442	Stone & Webster Construction Inc	DILLON SUPPLY CO	Tagging ASME III Piping

285	132175F003781	WSPM004491	Stone & Webster Construction Inc	DILLON SUPPLY CO	REMOVABLE FORMWORK CONSTRUCTION AID FOR THE ELCTRICAL CABLE TRAY SUPPORTS AT THE 315 BUILDING. WORK PACKAGE SV0-0000-CCW-CV1583

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CONFIDENTIAL TRADE SECRET INFORMATION

286	132175F003804	WSPM010300	Stone & Webster Construction Inc	DILLON SUPPLY CO	For Cleaning Rust from Piping
287	132175F003919	WSPM010619	Stone & Webster Construction Inc	DILLON SUPPLY CO	Mechanical Module Valve Removal/Storage
288	132175F004082	WSPM010638	Stone & Webster Construction Inc	DILLON SUPPLY CO	For Rigging Forms
289	132175F004585	WSPM004920	Stone & Webster Construction Inc	DILLON SUPPLY CO	Louvers to be used for the tents
290	132175F004597	WSPM010601	Stone & Webster Construction Inc	DILLON SUPPLY CO	Temporary Construction - BOP
291	132175F004622	WSPM010602	Stone & Webster Construction Inc	DILLON SUPPLY CO	Temporary Construction - BOP Plumbing
292	132175F004629	WSPM010549	Stone & Webster Construction Inc	DILLON SUPPLY CO	SHIPPING SUPPLIES FOR M&TE CALIBRATION LAB
293	132175F004798	WSPM013317	Stone & Webster Construction Inc	DILLON SUPPLY CO	Temporary Construction Aid - TI4
294	132175F004827	WSPM004931	WECTEC Global Project Services, Inc.	DILLON SUPPLY CO	Temporary Construction Aid - Ice Machine reinstallation
295	132175F005131	WSPM009952	WECTEC Global Project Services, Inc.	DILLON SUPPLY CO	to be used for changes to the security post #1
296	132175F005416	WSPM009729	WECTEC Global Project Services, Inc.	DILLON SUPPLY CO	Temporary Construction - Testing For Nuclear Island 3 Piping Group
297	132175F005739	WSPM009805	WECTEC Global Project Services, Inc.	DILLON SUPPLY CO	Temporary Construction - Turbine Island 4 - Expansion Joints
298	132175F005775	WSPM010130	WECTEC Global Project Services, Inc.	DILLON SUPPLY CO	To be used at security post #1 to replace the damaged unit
299	J132175-FPR13-01107	WSPM002110	Stone & Webster Construction Inc	DILLON SUPPLY CO	Ex-Core conduit installation, No pkg yet, Construction Aid Material
300	WVG3000179	WVG3000179	WECTEC Global Project Services, Inc.	DILLON SUPPLY CO	Drawing clamps to be used in everyday work in Nuclear Island 3.
301	WVG3001301	WVG3001301	WECTEC Global Project Services, Inc.	DILLON SUPPLY CO	Non-Safety, Non-permanent plant material needed for Turbine overhead crane test frame-Plate - A36 1" X 6' X 8', QA Category III, Safety Class E, Storage Level D
302	132175F000304	WSPM013210	Stone & Webster Construction Inc	DIRECTV	To add additional funds to PO #660182-0P Direct TV
303	WVG3000468	WVG3000468	Stone & Webster	DIVERSIFIED INFORMATION	

			Construction Inc	SOURCES INC	INVESTIGATION SERVICE - 725612 3P TRANSFER

304	804026-3M	WSPM004358	Stone & Webster Construction Inc	DOCTORS HOSPITAL CENTER FOR OCC MED	Review Medical Questionaire
305	808756 3P	WSPM004359	Stone & Webster Construction Inc	DOCTORS HOSPITAL CENTER FOR OCC MED	Services for Audiograms and Hepatitis B
306	WVG3000301	WVG3000301	WECTEC Global Project Services, Inc.	DOCTORS HOSPITAL CENTER FOR OCC MED	Replace PO 808756 and add funds in the amount of $10,000.00
307	WVG3000473	WSPM015494	Stone & Webster Construction Inc	DOCTORS HOSPITAL CENTER FOR OCC MED	SPECIMEN COLLECTION - 844709 3P TRANSFER
308	132175-C121.04	WSPM004575	Stone & Webster Construction Inc	DUBOSE NATIONAL ENERGY SERVICES INC	B31.1 Pipe and Fittings for Building 315
309	132175-C121.09	WSPM013106	Stone & Webster Construction Inc	DUBOSE NATIONAL ENERGY SERVICES INC	Carbon-Steel Piping and Accessories for YFS Pump
310	132175-C125.03	WSPM013105	Stone & Webster Construction Inc	DUBOSE NATIONAL ENERGY SERVICES INC	Piping and Fittings for the WRS and WLS Systems
311	132175-D220.09	WSPM011848	Stone & Webster Construction Inc	DUBOSE NATIONAL ENERGY SERVICES INC	Non-Safety Related Embed Plates
312	132175-D500.09	WSPM003379	Stone & Webster Construction Inc	DUBOSE NATIONAL ENERGY SERVICES INC	Structural Steel & Fasteners for Cat II/SC-D
313	132175-D500.13	WSPM003376	Stone & Webster Construction Inc	DUBOSE NATIONAL ENERGY SERVICES INC	Safety Related Anchors and Plates
314	132175-D500.38	WSPM003370	Stone & Webster Construction Inc	DUBOSE NATIONAL ENERGY SERVICES INC	Unit 3 Annex Building Headed Anchor Nelson Studs
315	132175-JT02.02 RELEASE 1	WSPM010069	WECTEC Global Project Services, Inc.	DUBOSE NATIONAL ENERGY SERVICES INC	Non Class 1E Instrument Tubing
316	132176-D500.27	WSPM003198	Stone & Webster Construction Inc	DUBOSE NATIONAL ENERGY SERVICES INC	Nelson Studs and Ferrules for Unit 4 CA04 Module
317	132176-D500.46	WSPM003195	WECTEC Global Project Services, Inc.	DUBOSE NATIONAL ENERGY SERVICES INC	Miscellaneous Structural Steel for Cat II/SC-D Applications
318	WVG3000858	WVG3000858	WECTEC Global Project Services, Inc.	DUBOSE NATIONAL ENERGY SERVICES INC	Material to be left in place and used for fastening electrical cable trays to supports within the Unit 3 Turbine Building, work package SV3-2020-ERW-EL4488
322	J132175-G280.01	WSPM002107	Stone & Webster Construction Inc	E BEAUDREY AND CIE	Condenser Tube Cleaning Equipment

323	J132176-G280.01	WSPM002276	Stone & Webster Construction Inc	E BEAUDREY AND CIE	Condenser Tube Cleaning Equipment|
324	J132175-J800B-00	WSPM009759	Stone & Webster Construction Inc	EARTHTEC INC	Nuclear Island MSE Wall Design and Materials Construction Su
325	132176-PY02.01	WSPM003034	Stone & Webster Construction Inc	EATON HYDRAULICS LLC	CDS Basket Strainers

326	132175-C900.02	WSPM015655	WECTEC Global Project Services, Inc.	ELEMENT MATERIALS TECHNOLOGY	Welding Procedure Qualification Testing Services
327	132176-MS10.00	WSPM000923	Stone & Webster Construction Inc	ELLIS & WATTS GLOBAL INDUSTRIES INC	MS10 Air Handling Units
328	132176-MS14.00	WSPM010395	Stone & Webster Construction Inc	ELLIS & WATTS GLOBAL INDUSTRIES INC	MS14 - Containment Recirculation Fan Coil Units
329	689076	WSPM004313	Stone & Webster Construction Inc	ELSOHLY LABORATORIES INC	Blind Quality control urine specimens
330	WVG3000601	WVG3000601	Stone & Webster Construction Inc	ELSOHLY LABORATORIES INC	BLIND QC SAMPLES - 689076 OP TRANS
331	132175F000572	WSPM004635	Stone & Webster Construction Inc	EMERGENCY EQUIPMENT SERVICE INC	Emergency Equipment Service - Establish New PO in SmartPlant Old PO 762134
332	J132175-K219-01	WSPM013366	Stone & Webster Construction Inc	ENDRESS AND HAUSER INC	Radar/Ultrasonic Level XMTRS
333	J132175-K305.02	WSPM009819	Stone & Webster Construction Inc	ENDRESS AND HAUSER INC	YFS Differential Pressure Transmitter (Tank Level)|
334	J132175-K416.01	WSPM009818	Stone & Webster Construction Inc	ENDRESS AND HAUSER INC	RTD Thermowell
335	132175-C802.07	WSPM004584	Stone & Webster Construction Inc	ENERGY AND PROCESS CORP	Safety Class E Fasteners for the ASS, CDS, SWS, and TCS Systems
336	132175-C811.00A REL 1	WSPM004582	WECTEC Global Project Services, Inc.	ENERGY AND PROCESS CORP	Safety Related Gaskets
337	132175-C910.20	WSPM003266	WECTEC Global Project Services, Inc.	ENERGY AND PROCESS CORP	HDPE Pipe and Fittings - Building 304
338	132175F002044	WSPM004435	Stone & Webster Construction Inc	ENERGY AND PROCESS CORP	Pipe for Weld Test
339	132175F004277	WSPM004875	Stone & Webster Construction Inc	ENERGY AND PROCESS CORP	Temporary Construction - Testing
340	132175F004381	WSPM004860	Stone & Webster Construction Inc	ENERGY AND PROCESS CORP	Temporary Construction - BOP - Testing/Plumbing
341	132175F004453	WSPM011192	Stone & Webster Construction Inc	ENERGY AND PROCESS CORP	Pro Heat stiffener bars
342	132175F004755	WSPM011193	Stone & Webster Construction Inc	ENERGY AND PROCESS CORP	Temporary Construction Aid - Shim Material for Tanks
343	132176-C913.01	WSPM003760	Stone & Webster Construction Inc	ENERGY AND PROCESS CORP	Fire Protection System (FPS) Ductile Iron Piping and Fittings
344	132175-C913.01	WSPM003264	Stone & Webster Construction Inc	ENERGY AND PROCESS CORP	Fire Protection System (FPS) Ductile Iron Piping and Fittings

345	132175-D100.10	WSPM003252	Stone & Webster Construction Inc	ENERGY AND PROCESS CORP	Material for Fabrication of RWS Pipe Supports for Building 315
346	132175-D500.06 REL 002	WSPM003453	Stone & Webster Construction Inc	ENERGY AND PROCESS CORP	D500.06-010 - I17542563 - Channel, A36
347	132175-D500.06 REL 003	WSPM003452	Stone & Webster Construction Inc	ENERGY AND PROCESS CORP	Safety Related Miscellaneous Structural Steel Blanket
348	132175-D500.06 REL 005	WSPM003384	WECTEC Global Project Services, Inc.	ENERGY AND PROCESS CORP	Safety Related Misc. Structural Steel
349	132175-D500.06-REL 006	WSPM003383	WECTEC Global Project Services, Inc.	ENERGY AND PROCESS CORP	D500.06-019 - I17542572 - Tube - Square,
350	132175-D500.06-REL 007	WSPM003382	WECTEC Global Project Services, Inc.	ENERGY AND PROCESS CORP	Safety Related Miscellaneous Structual Steel
351	132175-D500.06-REL 008	WSPM003381	WECTEC Global Project Services, Inc.	ENERGY AND PROCESS CORP	Safety Related Miscellaneous Structual Steel
352	132175-D500.06-REL 010	WSPM003380	WECTEC Global Project Services, Inc.	ENERGY AND PROCESS CORP	Safety Related MiscMiscellaneous Structual Steel
353	132175-D500.06-REL 011	WSPM001223	WECTEC Global Project Services, Inc.	ENERGY AND PROCESS CORP	Safety Related Misc. Structual Steel
354	132175-D500.06-REL-013	WSPM001222	WECTEC Global Project Services, Inc.	ENERGY AND PROCESS CORP	Safety Related Misc. Structual Steel
355	WSV3B00034	WSV3B00034	WECTEC Global Project Services, Inc.	ENERGY AND PROCESS CORP	Release 14- Safety Related Misc. Structual Steel
356	132175-C913.06	WSPM010070	WECTEC Global Project Services, Inc.	ENERGY STEEL AND SUPPLY CO	Fiberglass Piping and Fittings for ZRS and DOS
357	132175-D500.48	WSPM003367	WECTEC Global Project Services, Inc.	ENERGY STEEL AND SUPPLY CO	Structural and Misc Steel for WWS Oil Separator
358	132175F003251	WSPM003086	Stone & Webster Construction Inc	ENGINEERED FLOW LLC	New Jockey Pump Rotation Check & Controller Setup After Installation
359	4500722495	4500722495	WECTEC Global Project Services, Inc.	ENGLEWOOD ELECTRICAL SUPPLY CO	Equipment Repair Parts and Service
360	132175F004756	WSPM013752	Stone & Webster Construction Inc	ENVIRONMENTAL EXPRESS INC	Commissioning - Bridge Lab Test Equipment
361	132175F004812	WSPM009915	Stone & Webster Construction Inc	ENVIRONMENTAL EXPRESS INC	COMMISSIONING WTR TREATMENT LAB - CONSUMABLES
362	132175F004813	WSPM009920	Stone & Webster Construction Inc	ENVIRONMENTAL EXPRESS INC	Commissioning - Water Treatment Lab Test Equipment
363	132175F004814	WSPM003817	WECTEC Global Project Services, Inc.	ENVIRONMENTAL EXPRESS INC	Commissioning - Water Treatment Lab Test
364	WVG3000088	WVG3000088	WECTEC Global Project Services, Inc.	ENVIRONMENTAL EXPRESS INC	Water Quality Lab Turbidimeter Sample Cells for testing .

365	WVG3001242	WVG3001242	WECTEC Global Project Services, Inc.	ER TECHNOLOGIES	TRAINING FOR SCBA
366	132175-G260.03	WSPM010230	Stone & Webster Construction Inc	EVOQUA WATER TECHNOLOGIES LLC	RWS Intake Screening System
367	WVG3000070	WVG3000070	Stone & Webster Construction Inc	EXAKTIME INNOVATIONS INC	ExacTime Time Keeping System
368	132175-C802.02	WSPM004585	Stone & Webster Construction Inc	FASTENAL CO INC	Fasteners for Pumphouse
369	132175-C802.11	WSPM011167	Stone & Webster Construction Inc	FASTENAL CO INC	WLS & WRS System Gaskets, Tubing Fittings and Nuts
370	132175-C802.12	WSPM011168	Stone & Webster Construction Inc	FASTENAL CO INC	Turbine Building Spare Materials
371	132175-D500.32	WSPM003373	Stone & Webster Construction Inc	FASTENAL CO INC	Fasteners for Unit 3 Turbine Building
372	132175-D500.36	WSPM003371	Stone & Webster Construction Inc	FASTENAL CO INC	Fasteners for Annex Building
373	132175F001329	WSPM004606	Stone & Webster Construction Inc	FASTENAL CO INC	Formwork for NI 3 (Jerry Steffey)
374	132175F001333	WSPM003052	Stone & Webster Construction Inc	FASTENAL CO INC	Construction Aides; Please mark Boxes III-E
375	132175F001691	WSPM004403	Stone & Webster Construction Inc	FASTENAL CO INC	Batch Plant - Hardware - nuts,bolts,washers,lock-washers
376	132175F002471	WSPM004411	Stone & Webster Construction Inc	FASTENAL CO INC	Temporary Construction - Plumbing - BOP
377	132175F003501	WSPM004527	Stone & Webster Construction Inc	FASTENAL CO INC	Construction Aid
378	132175F003921	WSPM011190	Stone & Webster Construction Inc	FASTENAL CO INC	Construction aid material to be used for the MAB End Wall Removal Screw, work package SV-847-SSW-TP1813
379	132175F004008	WSPM011191	Stone & Webster Construction Inc	FASTENAL CO INC	CA01 Module Leakchase Piping Temporary Supports
380	132175F004066	WSPM004852	Stone & Webster Construction Inc	FASTENAL CO INC	Temporary Electrical Material (Fasteners)
381	132175F004446	WSPM010488	Stone & Webster Construction Inc	FASTENAL CO INC	Temporary Fasteners for the CA05 Module Platen
382	132175F004716	WSPM004917	Stone & Webster Construction Inc	FASTENAL CO INC	Temporary Construction Aid - BOP
383	132175F004783	WSPM011194	Stone & Webster Construction Inc	FASTENAL CO INC	BOLTS AND WASHERS FOR ASSEMBLY OF READY ROOFS
384	132175F004886	WSPM004929	Stone & Webster Construction Inc	FASTENAL CO INC	Nonpermanent Plant Construction Aid Material. For use by reinforcing iron workers NI3.

385	132175F004901A	WSPM004928	Stone & Webster Construction Inc	FASTENAL CO INC	Nonpermanent Plant Construction Aid Material. Fasteners For Use In Nuclear Island 4 By Carpenters.
386	132175F005074	WSPM009950	WECTEC Global Project Services, Inc.	FASTENAL CO INC	Temporary Construction Aid - Turbine Island 4 - Use: Setting pumps and removed after completed
387	132175F005220	WSPM009957	WECTEC Global Project Services, Inc.	FASTENAL CO INC	*HOT ITEM* TEMPORARY CONST AID - FULLY THREADED METRIC CAP SCREWS FOR TI-4 START UP PUMPS
388	132175F005271	WSPM004944	WECTEC Global Project Services, Inc.	FASTENAL CO INC	U-bolts For Temporary Pipe Support. Nonpermanent Plant.
389	132175F005292	WSPM011195	WECTEC Global Project Services, Inc.	FASTENAL CO INC	Construction Aid Material. Nonpermanent Plant. Containment NI3.
390	132175F005329	WSPM011164	WECTEC Global Project Services, Inc.	FASTENAL CO INC	Construction Aids For Embeds, Containment NI3. Nonpermanent Plant.
391	132175F005493	WSPM004899	WECTEC Global Project Services, Inc.	FASTENAL CO INC	Non-permanent plant construction aid.
392	132175F005567	WSPM004893	WECTEC Global Project Services, Inc.	FASTENAL CO INC	Nonpermanent Plant Construction Aid Material. Fasteners For Use By The Carpenters NI3.
393	132175F005602	WSPM004880	WECTEC Global Project Services, Inc.	FASTENAL CO INC	1/2” Cable for Tent tie down across site due to wind
394	132175F005773	WSPM002963	WECTEC Global Project Services, Inc.	FASTENAL CO INC	Touch up coatings on non-safety related conduit (work package SV4-CA20-ERW-EL6714)
395	132175F005789	WSPM004705	WECTEC Global Project Services, Inc.	FASTENAL CO INC	Magnets for securing safety netting/Micellaneous items to modules (Night Shift)
396	132175F005791	WSPM011897	WECTEC Global Project Services, Inc.	FASTENAL CO INC	Material to be left in place and used for repairing sheet metal and flashing at the 315 building pumphouse, work package SV0-0000-SSW-CV7453
397	132176-C802.13	WSPM004728	Stone & Webster Construction Inc	FASTENAL CO INC	Turbine Building and Condenser Spare Materials

398	132176F000019	WSPM003134	Stone & Webster Construction Inc	FASTENAL CO INC	Unit 4 turbine building construction aid materials for el 100’-0”
399	132176F000033	WSPM003133	Stone & Webster Construction Inc	FASTENAL CO INC	Install for repair/rework of damaged studs in accordance with EDCR SV0-SS01-GEF-000037. Turbine Building Units 4
400	132176F000064	WSPM011154	Stone & Webster Construction Inc	FASTENAL CO INC	U-Bolts
401	J132175-FPR12-02393	WSPM010470	Stone & Webster Construction Inc	FASTENAL CO INC	Installation for 300 series bldgs YFS
402	J132175-FPR12-02397	WSPM010415	Stone & Webster Construction Inc	FASTENAL CO INC	Installation for 300 series buildings PWS
403	WVG3000155	WVG3000155	WECTEC Global Project Services, Inc.	FASTENAL CO INC	Material to be left in place and used for repairing sheet metal and flashing at the 315 building pumphouse (used for 132175F005791), wp SV0-0000-SSW-CV7453
404	WVG3001252	WVG3001252	WECTEC Global Project Services, Inc.	FASTENAL CO INC	Temporary Construction Aide to be Abandoned in Concrete, for Nuclear Island 3 Carpenters to secure embeds to rebar.
405	WVG3001280	WVG3001280	WECTEC Global Project Services, Inc.	FASTENAL CO INC	Material to complete redi roof for labeling conex for PM
406	WVG3001325	WVG3001325	WECTEC Global Project Services, Inc.	FASTENAL CO INC	Non Permanent plant construction aide to be used in Unit 3 CA20 module to aide in installation of nelson studs.
407	WVG3001332	WVG3001332	WECTEC Global Project Services, Inc.	FASTENAL CO INC	BOP TEMPORARY CONSTRUCTION AID USED FOR THE SES CV-2055
408	WVG3001336	WVG3001336	WECTEC Global Project Services, Inc.	FASTENAL CO INC	spray foam for NI4-craft tents
409	WVG3001350	WVG3001350	WECTEC Global Project Services, Inc.	FASTENAL CO INC	Material to complete Redi Roof for labeling connex for PM
410	WVG3001370	WVG3001370	WECTEC Global Project Services, Inc.	FASTENAL CO INC	Material needed to build valve stands for CRSP
411	WVG3001380	WVG3001380	WECTEC Global Project Services, Inc.	FASTENAL CO INC	Fasteners. Construction Aid Mateiral. Nonpermanent Plant. NI3 Carpenters.

412	WVG3001388	WVG3001388	WECTEC Global Project Services, Inc.	FASTENAL CO INC	BOP TEMPORARY CONSTRUCTION AID FOR UNIT 4 WWS SYSTEM SV4-MT71-00-85001
413	WVG3001389	WVG3001389	WECTEC Global Project Services, Inc.	FASTENAL CO INC	BOP TEMPORARY CONSTRUCTION AID FOR UNIT 4 WWS SYSTEM SV4-MT71-00-85001
414	WVG3001403	WVG3001403	WECTEC Global Project Services, Inc.	FASTENAL CO INC	Annex 3 Temporary Construction Aide
415	WVG3001441	WVG3001441	WECTEC Global Project Services, Inc.	FASTENAL CO INC	BOP TEMPORARY CONSTRUCITON AID MATERIAL USED FOR CONCRETE FORMS ON STAINLESS STEEL EMBEDS
416	WVG3001457	WVG3001457	WECTEC Global Project Services, Inc.	FASTENAL CO INC	BOP TEMPORARY CONSTRUCTION AID MATERIAL WP# CV-6004
417	WVG3001460	WVG3001460	WECTEC Global Project Services, Inc.	FASTENAL CO INC	Carpenters Consumable Material
418	WVG3001469	WVG3001469	WECTEC Global Project Services, Inc.	FASTENAL CO INC	OFF-SITE WAREHOUSE/EQUIPMENT CLEANING FOR PM GROUP
419	WVG3001470	WVG3001470	WECTEC Global Project Services, Inc.	FASTENAL CO INC	Flat Washers for use by the carpenters in Nuclear Island 3. Nonpermanent Plant.
420	WVG3001479	WVG3001479	WECTEC Global Project Services, Inc.	FASTENAL CO INC	TI 4 TEMPORARY CONSTRUCTION AIDE
421	WVG3001492	WVG3001492	WECTEC Global Project Services, Inc.	FASTENAL CO INC	WASHER -FLAT 1” X2” OD THRU HARDENED PLAIN STEEL F436
422	WVG3001509	WVG3001509	WECTEC Global Project Services, Inc.	FASTENAL CO INC	THESE ARE USED ON THE ROOF PACKAGES.
423	WVG3001511	WVG3001511	WECTEC Global Project Services, Inc.	FASTENAL CO INC	TI3 CARPENTERS ROOF PACKAGES
424	844635-3M	WSPM004362	Stone & Webster Construction Inc	FERRELLGAS LP	Funding to be added to PO 844635 (Ferrell Gas), Donny Johnson
425	4500663963	4500663963	Westinghouse Electric Company LLC	FICKESS PUMPS	Gear Type Positive Displacement Pumps
426	132175F005411	WSPM003574	WECTEC Global Project Services, Inc.	FIRE TECHNOLOGY LLC	FIRE TECH LLC TO PERFORM (2) 5YR INTERN. TANK INSPEC.SPEC #SV0-MT40-Z0-002. ID# MT40A & MT40B NEAR 315 BLDG.

427	J132175-FPR13-02089	WSPM015354	Stone & Webster Construction Inc	FISCHER ENGINEERING CO	Weld coupons for Welder Qualification
428	WVG3001275	WVG3001275	WECTEC Global Project Services, Inc.	FISCHER ENGINEERING CO	WELD TEST COUPONS
429	132175F001561	WSPM009940	Stone & Webster Construction Inc	FISHER SCIENTIFIC CO LLC	PM Group Testing set up for Deionized water **RUSH PER HUGH BOURQUE***
430	132175F001631	WSPM009761	Stone & Webster Construction Inc	FISHER SCIENTIFIC CO LLC	Chemicals for the water quality lab **** rush Hugh Bourque ****
431	132175F002461	WSPM010052	Stone & Webster Construction Inc	FISHER SCIENTIFIC CO LLC	Water Quality Consumabels PM Group
432	132175F003988A	WSPM010657	Stone & Webster Construction Inc	FISHER SCIENTIFIC CO LLC	Water Lab Consumables - Electrode Filling Solution
433	132175F004445	WSPM004866	Stone & Webster Construction Inc	FISHER SCIENTIFIC CO LLC	ULTRA TAPE FOR TEMPORARY ACTIVITIES PM ACTIVITES
434	132175F004561	WSPM009922	WECTEC Global Project Services, Inc.	FISHER SCIENTIFIC CO LLC	WATER LAB EQUIPMENT (METERS, CONDUCTIVITY PROBE AND MODULES)
435	132175F004651	WSPM009906	Stone & Webster Construction Inc	FISHER SCIENTIFIC CO LLC	Commissioning - Water Treatment Lab Equipment
436	132175F005192	WSPM009961	WECTEC Global Project Services, Inc.	FISHER SCIENTIFIC CO LLC	Graduated Cylinders water lab
437	132175F005244A	WSPM009728	WECTEC Global Project Services, Inc.	FISHER SCIENTIFIC CO LLC	PM Water Quality Lab Supplies Pipette tips 100 to1000 microlite P/N 21R685 and stir bars
438	132175F005267	WSPM009730	WECTEC Global Project Services, Inc.	FISHER SCIENTIFIC CO LLC	WQL SUPPLIES weigh. dishes, cond cell pipette 10-100
439	132175F005328	WSPM009724	WECTEC Global Project Services, Inc.	FISHER SCIENTIFIC CO LLC	WQL Supplies, Timer, Hotplate, ATC Probe
440	132175F005498	WSPM010196	WECTEC Global Project Services, Inc.	FISHER SCIENTIFIC CO LLC	SG 893 2-propanol,SG 2498 Stoddard Solvent PM Temp. Const. activities fasteners on ACC/ SSC's @ Wboro WH. WP# SV3-PXS-MT-02A
441	WVG3000873	WVG3000873	Stone & Webster Construction Inc	FISHER SCIENTIFIC CO LLC	2" and 3" White , Blue Stripe tape for PM Activities
442	WVG3001344	WVG3001344	WECTEC Global Project Services, Inc.	FISHER SCIENTIFIC CO LLC	3" White, Blue Stripe Tape for CRSP to retape VPCI during walk downs
443	132175F003770-A	WSPM015406	Stone & Webster Construction Inc	FLEETPRIDE	Batch Plant - photoeye, tubing, solenoid

444	132175-P110.05	WSPM003924	WECTEC Global Project Services, Inc.	FLOWSERVE PUMP DIVISION	Inspection / Refurbishment Services for RWS and CWS Pumps and Motors
445	J132175-P810.02	WSPM009809	Stone & Webster Construction Inc	FLOWSERVE PUMP DIVISION	RWS Well Water Make-up Pump
446	J132175-P810.03	WSPM010147	Stone & Webster Construction Inc	FLOWSERVE PUMP DIVISION	River Water & Screen Wash Pumps|
447	J132175-P110.01	WSPM009820	Stone & Webster Construction Inc	FLOWSERVE US INC	RWS Well Water Transfer Pumps
448	132175F001649	WSPM004458	Stone & Webster Construction Inc	FORTRANS INC	Batch Plant - Increase funding PO# 714067 - Fortrans - For one Year
449	132175F003116	WSPM010098	Stone & Webster Construction Inc	FORTRANS INC	Batch Plant - pH Sensors
450	132175F003131	WSPM010097	Stone & Webster Construction Inc	FORTRANS INC	Batch Plant - PLC for pH System
451	J132175-D700.01	WSPM010150	Stone & Webster Construction Inc	GAFFEY	Crane Rail Procurement
452	132175-EW06.01	WSPM015608	Stone & Webster Construction Inc	GENERAL CABLE INDUSTRIES	Class 1E Low Voltage CRDM and DRPI Cables
453	132175-EW21.01	WSPM015640	Stone & Webster Construction Inc	GENERAL CABLE INDUSTRIES	Instrumentation and Thermocouple Extension Cables
454	132175-EW60.01	WSPM015641	Stone & Webster Construction Inc	GENERAL CABLE INDUSTRIES	Class 1E Control Cables
455	132176-EW21.01	WSPM015642	Stone & Webster Construction Inc	GENERAL CABLE INDUSTRIES	Instrumentation and Thermocouple Extension Cables
456	132176-EW60.01	WSPM015644	Stone & Webster Construction Inc	GENERAL CABLE INDUSTRIES	Class 1E Control Cables
458	132175F001078	WSPM004622	Stone & Webster Construction Inc	GENERAL EQUIPMENT AND SUPPLY	Establish a Blanket PO for Refurbishment of Site Equipment: Print Shacks, Fire Cabinets & Gang Boxes
459	132175F003970	WSPM004669	Stone & Webster Construction Inc	GENERAL EQUIPMENT AND SUPPLY	Rebar bender to be used to allow ANnex Construction to field fabricate/bend rebar due to extensive E&DCR issues
460	132175F005560	WSPM004896	WECTEC Global Project Services, Inc.	GENERAL EQUIPMENT AND SUPPLY	REBAR BENDER 2 YEAR RENTAL FOR USE AT ANNEX 3/4 TRANSFORMER 3/4 AND DIESEL GENERATORS. ASSIST IN FIELD FABRICATION/BEND REBAR
461	132175F005616	WSPM004882	WECTEC Global Project	GENERAL EQUIPMENT	ROD CHOMPER FOR ANNEX 3/4 - TRANSFORMER 3/4 -

			Services, Inc.	AND SUPPLY	FABRICATION OF REBAR 2 YEAR RENTAL

462	132175F005715	WSPM004891	WECTEC Global Project Services, Inc.	GENERAL EQUIPMENT AND SUPPLY	Temporary Construction - BOP - Circulating Water System
463	WVG3000751	WVG3000751	Stone & Webster Construction Inc	GENERAL EQUIPMENT AND SUPPLY	Rebar Equipment for Fabrication Shop
464	WVG3001340	WVG3001340	WECTEC Global Project Services, Inc.	GENERAL EQUIPMENT AND SUPPLY	Required Equipment for sheet metal fab shop. (Safety issue)
465	132175-PY55.00	WSPM003914	Stone & Webster Construction Inc	GENERAL RUBBER CORPORATION	PY55 - Non-Metallic Expansion Joints
466	132176-PY55.00	WSPM003141	Stone & Webster Construction Inc	GENERAL RUBBER CORPORATION	PY55 - Non-Metallic Expansion Joints
467	WVG3000410	WVG3000410	WECTEC Global Project Services, Inc.	GEORGIA POWER CO	TRANSFER OF FUNDS FROM 885042-3P
468	4500721598	4500721598	WECTEC Global Project Services, Inc.	GERALD JONES FORD LINCOLN	Equipment Repair Parts and Service
469	132175-E108.01	WSPM003355	Stone & Webster Construction Inc	GEXPRO	Well Water Cable Tray|
470	132175-E112.03	WSPM003354	Stone & Webster Construction Inc	GEXPRO	Fittings|
479	132175F001339	WSPM004604	Stone & Webster Construction Inc	GEXPRO	Gexpro Min/Max Warehouse Services
512	WVG3001317	WVG3001317	WECTEC Global Project Services, Inc.	GEXPRO	to be left in place and used for HVAC thermostat to control temperature in various rooms for bldg 315
513	WVG3001341	WVG3001341	WECTEC Global Project Services, Inc.	GEXPRO	NI4 Scaffold Consumables
514	WVG3001502	WVG3001502	WECTEC Global Project Services, Inc.	GEXPRO	Material to be left in place and used for Unit 3 transformer yard, work package SV3-ZAS-ERW-EL3254
515	WVG3001508	WVG3001508	WECTEC Global Project Services, Inc.	GEXPRO	MATERIAL NEEDED FOR BOXES AND DOORS.
517	WVG3000869	WVG3000869	WECTEC Global Project Services, Inc.	GEXPRO	BOP TEMPORARY CONSTRUCTION AID FOR BATHRROOMS/ USE ON ENTIRE SITE
518	WVG3001025	WVG3001025	WECTEC Global Project Services, Inc.	GEXPRO	MATERIAL LEFT IN PLACE ANNEX 3 CONDUIT INSTALLATION FOR BATTERY MONITORS IE WP SV3-4031-ERW-861316,861317,861318 & 861319

519	WVG3001206	WVG3001206	WECTEC Global Project Services, Inc.	GEXPRO	Crimp Tool Force Gauge, Panduit (Huskie)
520	WVG3001266	WVG3001266	WECTEC Global Project Services, Inc.	GEXPRO	HVAC area heater to be left in place for ZRS diesel generator room for building 315
521	WVG3001284	WVG3001284	WECTEC Global Project Services, Inc.	GEXPRO	20”X24”X4” PLEATED PRE-FILTER 91-956
522	WVG3001288	WVG3001288	WECTEC Global Project Services, Inc.	GEXPRO	120 VOLT LED LIGHTING TO ILLUMINATE SHELVING IN SHOP IN THE 184 BLDG.
523	WVG3001307	WVG3001307	WECTEC Global Project Services, Inc.	GEXPRO	Material to be left in place and used for Unit 3 ELS Transformer Yard Lighting, work package SV3-0000-ELW-EL7683
524	WVG3001324	WVG3001324	WECTEC Global Project Services, Inc.	GEXPRO	Integrated Head Package (IHP) Consumables
525	WVG3001327	WVG3001327	WECTEC Global Project Services, Inc.	GEXPRO	to be left in place and used for selector switch to control HVAC fans and louvers for bldg 315
526	WVG3001351	WVG3001351	WECTEC Global Project Services, Inc.	GEXPRO	Material left in place. Replacement Multiple Switch Contactors on PWS Skid Building 315 WP# SV0-PWS-EWW-EL3561 / SV0-010-EWW-861550
527	WVG3001352	WVG3001352	WECTEC Global Project Services, Inc.	GEXPRO	(IHP) AIR COMPRESSOR ELECTRICAL CONNECTION
528	WVG3001356	WVG3001356	WECTEC Global Project Services, Inc.	GEXPRO	to be left in place and used for dowel in rebar into concrete for the Unit 3 WWRB housekeeping pad per design, work package SV3-WWS-CCW-CV3367
529	WVG3001360	WVG3001360	WECTEC Global Project Services, Inc.	GEXPRO	to be used for bldg 315 temporary well pump 3 & 4 VFD, work package SV0-RWS-T4Y-001
530	WVG3001365	WVG3001365	WECTEC Global Project Services, Inc.	GEXPRO	To be used for bldg 315, relay to control HVAC fans and louvers
531	WVG3001372	WVG3001372	WECTEC Global Project Services, Inc.	GEXPRO	Temporary Construction Aid - Annex 3 Sikaflex to seal formwork & concrete placement WP# SV3-

					4051-CCW-CV8905, SV3-4041-CCW-CV3182
532	WVG3001381	WVG3001381	WECTEC Global Project Services, Inc.	GEXPRO	Material to be left in place and used for Unit 3 ELS Transformer Yard Lighting, work package SV0-0000-ELW-EL7397
533	WVG3001395	WVG3001395	WECTEC Global Project Services, Inc.	GEXPRO	Material to be left in place and used for caulking the gap seals for IE rooms 20501, 20502 and 20503, work package SV3-2050-SSW-CV8966
534	WVG3001398	WVG3001398	WECTEC Global Project Services, Inc.	GEXPRO	VpCI 126 BAGS FOR PM SCHEDULED ACTIVITYS
535	WVG3001399	WVG3001399	WECTEC Global Project Services, Inc.	GEXPRO	to be left in place and used for bldg 315, SV0-ZRS-JD-MCP001, work package SV0-EDS-11-IT002
536	WVG3001400	WVG3001400	WECTEC Global Project Services, Inc.	GEXPRO	Material to be left in place and used for BLDG 315 SV0-ZRS-JD-MCP001, work package SV0-JQ70-JDB-800000
537	WVG3001420	WVG3001420	WECTEC Global Project Services, Inc.	GEXPRO	Equipment for M&TE
538	WVG3001443	WVG3001443	WECTEC Global Project Services, Inc.	GEXPRO	Mechanical Modules (R251, R261, R219 & KB33) Grounding Clamps for Cable Trays
539	WVG3001489	WVG3001489	WECTEC Global Project Services, Inc.	GEXPRO	fLOOR SWEEP ROY FIELDING PTT: 395
540	WVG3001495	WVG3001495	WECTEC Global Project Services, Inc.	GEXPRO	Material to be left in place and used for Unit 3 ELS Transformer Yard Lighting, work package SV0-0000-ELW-EL7397
541	WVG3001497	WVG3001497	WECTEC Global Project Services, Inc.	GEXPRO	Material to be left in place and used for Unit 3 Transformer yard, work package SV3-0000-ELW-EL7397
542	WVG4001241	WVG4001241	WECTEC Global Project Services, Inc.	GEXPRO	Material to be left in place and used for Unit 4 ZAS transformer yard lighting, work package SV0-0000-EGW-EL3556
543	WVG4001250	WVG4001250	WECTEC Global Project Services, Inc.	GEXPRO	Material to be left in place and used for Unit 4 ELS Transformer Yard Lighting, work package SV4-0000-

					EL-001
544	WSV3B00033	WSV3B00033	WECTEC Global Project Services, Inc.	GEXPRO	132175-E112.06-REL-022 Non-Safety Electrical Blanket Order
545	WSV3A00003	WSV3A00003	WECTEC Global Project Services, Inc.	GEXPRO	to be left in place and used for replacement of SV0-PWS-JE-LT506B, work package SV0-YFS-01-IT002/SV0-YFS-01-IT003
546	WSV3M00010	WSV3M00010	WECTEC Global Project Services, Inc.	GEXPRO	to be left in place and used for yard fire water tank temperture transmitter, work package SV0-YFS-01-1T001
548	132175F005235	WSPM004946	WECTEC Global Project Services, Inc.	GLOBAL EQUIPMENT CO INC - INDL	HEPA Filters for PAPR's
549	132175F005336	WSPM004938	WECTEC Global Project Services, Inc.	GLOBAL EQUIPMENT CO INC - INDL	Annex 3 / Transformer Blue Recycling Tilt Trash Bin
550	132175F005767	WSPM010121	WECTEC Global Project Services, Inc.	GLOBAL EQUIPMENT CO INC - INDL	sink and shelves used for cleaning station in bldg.142A and batch patch
551	132175F006003	WSPM010209	WECTEC Global Project Services, Inc.	GLOBAL EQUIPMENT CO INC - INDL	Totes to carry work packages. NI3 Structural group.
552	132175F006018	WSPM010210	WECTEC Global Project Services, Inc.	GLOBAL EQUIPMENT CO INC - INDL	KEY BOX-12-1/64"H X 8-3/16"WX 2 3/4" D-40 KEY CAP. STEEL FOR TURBINE #3 ELECTRICIANS
553	132175F006021	WSPM010211	WECTEC Global Project Services, Inc.	GLOBAL EQUIPMENT CO INC - INDL	Locks to be used for equipment clearance and tagging during the initial test program
554	132175F006022	WSPM010022	WECTEC Global Project Services, Inc.	GLOBAL EQUIPMENT CO INC - INDL	Temporary Construction - Bolting @ Building 315 - BOP
555	WVG3000013	WVG3000013	WECTEC Global Project Services, Inc.	GLOBAL EQUIPMENT CO INC - INDL	Band saw coolant for cutting metal
556	WVG3000219	WVG3000219	WECTEC Global Project Services, Inc.	GLOBAL EQUIPMENT CO INC - INDL	Computer Presentation Workstation
557	WVG3000355	WVG3000355	WECTEC Global Project Services, Inc.	GLOBAL EQUIPMENT CO INC - INDL	Replacement Brush Heads, Cart Trash Bag
558	WVG3000391	WVG3000391	Stone & Webster Construction Inc	GLOBAL EQUIPMENT CO INC - INDL	Material to be used as temporary supply and return for the climate control of installed permanent plant equipment
559	WVG3000699	WVG3000699	WECTEC Global Project Services, Inc.	GLOBAL EQUIPMENT CO INC - INDL	Annex 3 Night Shift - Heaters used in Battery Rooms

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560	WVG3000789	WVG3000789	WECTEC Global Project Services, Inc.	GLOBAL EQUIPMENT CO INC - INDL	to be used on the Unit 3 Initial Energization Temp Air for heating battery rooms
561	132175F004659	WSPM010547	Stone & Webster Construction Inc	GRAPHIC PRODUCTS INC	labeling materials for Preventive Maintenance temporay Construction activities
562	132175F005614	WSPM009786	WECTEC Global Project Services, Inc.	GRAPHIC PRODUCTS INC	PM Labeling team to labeling supplies to label material at the 315 Bldg. in prep to turn bldg over the SNC .
563	132175-ER01.02	WSPM002959	Stone & Webster Construction Inc	GRAYBAR ELECTRIC COMPANY INC	Non-Class 1E Cable Tray and Fittings for Mechanical Modules
564	132176-ER01.02	WSPM003960	Stone & Webster Construction Inc	GRAYBAR ELECTRIC COMPANY INC	Non-Class 1E Cable Tray and Fittings for Mechanical Modules
565	132175F000828 REL 027	WSPM004646	WECTEC Global Project Services, Inc.	GRIMCO INC	BLANKET ORDER TRANSFER 831033 3P
566	132175F000828 REL 029	WSPM004647	WECTEC Global Project Services, Inc.	GRIMCO INC	BLANKET ORDER TRANSFER 831033 3P
567	132175F005362	WSPM009721	WECTEC Global Project Services, Inc.	GRIMCO INC	Plexi-Glass, Paint Shop, Robert Hutto.
568	132175-E054.03	WSPM010277	Stone & Webster Construction Inc	GUTOR Electronic LLC	UPS Systems for RWI & TSC
569	4500712914	4500712914	WECTEC Contractors Inc	H&E EQUIPMENT SERVICES INC	Spare Parts
570	4500714034	4500714034	WECTEC Contractors Inc	H&E EQUIPMENT SERVICES INC	Spare Parts
571	4500714077	4500714077	WECTEC Contractors Inc	H&E EQUIPMENT SERVICES INC	Spare Parts
572	4500721413	4500721413	WECTEC Global Project Services, Inc.	H&E EQUIPMENT SERVICES INC	Equipment Repair Parts and Service
573	4500722095	4500722095	WECTEC Global Project Services, Inc.	H&E EQUIPMENT SERVICES INC	Equipment Repair Parts and Service
574	4500722207	4500722207	WECTEC Global Project Services, Inc.	H&E EQUIPMENT SERVICES INC	Equipment Repair Parts and Service
575	WVG3001500	WVG3001500	WECTEC Global Project Services, Inc.	H&E EQUIPMENT SERVICES INC	Parts for unit 102079 hydraulic valve repair
576	132175F004675	WSPM010791	Stone & Webster Construction Inc	H&H FLEET LLC	H&H Fleet Specialist, for service and repairs of Freightliner Trucks on rent from Charlie Brown Trucking, Blanket PO. $100,000.
577	132175-PL03.01	WSPM010449	Stone & Webster Construction Inc	HANSON PRESSURE PIPE INC	Shop Fabricated 120” Pipe and Supports

578	132176-PL03.01	WSPM010454	Stone & Webster Construction Inc	HANSON PRESSURE PIPE INC	Shop Fabricated 120” Pipe and Supports
579	WVG3000408	WVG3000408	WECTEC Global Project Services, Inc.	HARTFORD STEAM BOILER INSPC & INSR	TRANSFER OF FUNDS FROM 661204-OP
580	784064	WSPM004355	Stone & Webster Construction Inc	HAT D TRANSPORTATION CO	Add Funds to PO# 784064
581	132175F001704	WSPM004400	Stone & Webster Construction Inc	HAT D TRANSPORTATION CO	Batch Plant - Increase funding PO 784064 - Hat D - Pigs - one year
582	132175F003943	WSPM004493	Stone & Webster Construction Inc	HAT D TRANSPORTATION CO	Batch Plant - Add Funds to PO 892531 - Hat D - Balance due on rental
583	132175F000240	WSPM004658	Stone & Webster Construction Inc	HAVENS LEASING LLC	Batch Plant - Add funds to PO for Pig rental - PO 775650
584	132175F003002	WSPM010011	Stone & Webster Construction Inc	H&E	MANITOWOC 16000 DASH LIGHTS
585	132175F004958	WSPM004925	WECTEC Global Project Services, Inc.	H&E	PO covering $100,000 for crane parts, H&E Equipment Services, 10710 Nations Ford Rd, Charlotte NC 28273. POC Mickey Caldwell 704-504-2870.
586	4500721414	4500721414	WECTEC Global Project Services, Inc.	H&E	Equipment Repair Parts and Service
587	4500721416	4500721416	WECTEC Global Project Services, Inc.	H&E	Equipment Repair Parts and Service
588	4500722494	4500722494	WECTEC Global Project Services, Inc.	H&E	Equipment Repair Parts and Service
589	132175F001194	WSPM011108	Stone & Webster Construction Inc	HERC RENTALS INC	Breaking Concrete at Unit 3, Hyd. Hammer #1200 Rental for one Month
590	132175F002406	WSPM004389	Stone & Webster Construction Inc	HERC RENTALS INC	Add Funds to PO for Parts and Labor on PO 814259 Repair of Unit 094320007 Wacker from Hertz
591	132175F004097	WSPM004853	Stone & Webster Construction Inc	HERC RENTALS INC	4 light plants to re-place units # 62062, 63198, 63246, 63269. Rental for 36 months.
592	132175F004182	WSPM004874	Stone & Webster Construction Inc	HERC RENTALS INC	Requesting $1540.20 for damage to Genie 32’ platform lift Ser# GS3214A-135726.
593	132175F004188	WSPM004873	Stone & Webster Construction Inc	HERC RENTALS INC	Requesting $3,401.28 for damages to Hertz 85’ boom lift, Ser#

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					0300162565.
594	132175F004567	WSPM004837	Stone & Webster Construction Inc	HERC RENTALS INC	Request $9,216.22 for site damage to Hertz 135' boom lift Equip # 481-95-0027.
595	132175F004610	WSPM003071	Stone & Webster Construction Inc	HERC RENTALS INC	CLEANING BEFORE AND AFTER POURS ANNEX 3 AND TRANSFORMER AREA
596	132175F005562	WSPM010129	WECTEC Global Project Services, Inc.	HERC RENTALS INC	Temporary Construction Equipment Rental Excavation for Balance of Plant
597	132175F005564	WSPM004895	WECTEC Global Project Services, Inc.	HERC RENTALS INC	PO for ongoing Hertz JLG Training (started March 15, 2016)
598	132175F005893-REL-18	WSPM004714	WECTEC Global Project Services, Inc.	HERC RENTALS INC	HERTZ DIESEL HEATERS
599	132175F005893-REL-19	WSPM010614	WECTEC Global Project Services, Inc.	HERC RENTALS INC	HEATING AND AIR UNIT FOR CONCRETE COMPLEX
600	132175F006002	WSPM004719	WECTEC Global Project Services, Inc.	HERC RENTALS INC	Flexible HVAC Duct needed from Herc Rentals for a/c heating units Area(s) of the Plant to be used: NI3 AND NI4, AND 20â€ X 500â€™ of the Duct will be used for the new hire conex /ready roof building where the python safety tethering is done
601	4500714189	4500714189	WECTEC Contractors Inc	HERC RENTALS INC	Spare Parts
602	4500717517	4500717517	WECTEC Contractors Inc	HERC RENTALS INC	PARTS
603	WVG3005893-REL-17	WVG3005893	WECTEC Global Project Services, Inc.	HERC RENTALS INC	Heaters for the MAB
604	132175-J600.04 REL 5	WSPM007258	WECTEC Global Project Services, Inc.	HILTI CORP	Safety Related Hilti Product Blanket Order Release
605	132175-D500.52	WSPM011171	WECTEC Global Project Services, Inc.	HILTI INC	Hilti Material for Building 315
606	132175F004477	WSPM010487	Stone & Webster Construction Inc	HILTI INC	Replacement Battery & Charger for PS200 Hilti Rebar Finder
607	132175F006027	WSPM010026	WECTEC Global Project Services, Inc.	HILTI INC	HILTI X-SCAN PS 1000-B REBAR SCANNER NEEDED BY TURBINE #3 PIPEFITTERS

608	132175-J600.04 REL 2	WSPM010077	WECTEC Global Project Services, Inc.	HILTI INC	Safety Related Hilti Product Blanket Order Release
609	132175-J600.04 REL 3	WSPM010290	WECTEC Global Project Services, Inc.	HILTI INC	Safety Related Hilti Product Blanket Order Release

610	132175-J600.04 REL 4	WSPM007193	WECTEC Global Project Services, Inc.	HILTI INC	Safety Related Hilti Products Release
611	J132176-FPR134-00029	WSPM010263	Stone & Webster Construction Inc	HILTI INC	Construction Aid Anchors Unit 4 NI Mudmat
612	WVG3000210	WVG3000210	WECTEC Global Project Services, Inc.	HILTI INC	Temporary Anchor Bolts for securing unit 4 CA03 Module panels
613	WVG3000508	WVG3000508	Stone & Webster Construction Inc	HILTI INC	CA03 Module Temporary Anchor Bolts
614	WVG3000852	WVG3000852	WECTEC Global Project Services, Inc.	HILTI INC	PERMANENT PLANT MATERIAL FOR THE 315 BLDG
615	WVG4000267	WVG4000267	WECTEC Global Project Services, Inc.	HILTI INC	Material left in place for Unit 4 Turbine Building at 120' elevation for securing the DTS-MS-04A equipment in place, work package SV4-2040-CEW-CV5843
616	WVG3000678	WVG3000678	WECTEC Global Project Services, Inc.	H-MAC SYSTEMS INC	Equipment to be used on the Unit 3 Initial Energization Temp Air for Battery Rooms
617	132175F004475	WSPM005009	Stone & Webster Construction Inc	HOIST AND CRANE SYSTEMS INC	Hoist and Crane Systems, request $50,000 for annual inspections of overhead cranes in 167 and 184 Bldg.
618	132175F004475A	WSPM004868	Stone & Webster Construction Inc	HOIST AND CRANE SYSTEMS INC	Hoist and Crane Systems, request $50,000 for annual inspections of overhead cranes in 167 and 184 Bldg.
619	826508-3P	WSPM004964	Stone & Webster Construction Inc	HOIST AND CRANE SYSTEMS INC	The Commissioning, Inspection, Testing and Annual Inspection of the 2-3 Ton Overhead Cranes in the 184 Bldg
620	132175F006009	WSPM010076	WECTEC Global Project Services, Inc.	HOLLOWAY HOUSTON INC	lifting of the Containment Vessel Cover(s) for Unit 3 & Unit 4
621	132175F006052	WSPM010206	WECTEC Global Project Services, Inc.	HOLLOWAY HOUSTON INC	Rental of 800T G2160 Wide body shackle to be used for the lifting of CA20
622	132175-EF04.01	WSPM002948	WECTEC Global Project Services, Inc.	HOSE-MCCANN COMMUNICATIONS	Sound Power Phone Equipment
623	132176-EF04.01	WSPM003113	WECTEC Global Project Services, Inc.	HOSE-MCCANN COMMUNICATIONS	Sound Power Phone Equipment

624	WVG3001482	WVG3001482	WECTEC Global Project Services, Inc.	HSG CONSTRUCTORS LLC	BOP TEMPORARY CONSTRUCTION AID MATERIAL FOR TRANSFORMER UNIT 4 WP# 850019
625	132175F000671	WSPM010563	Stone & Webster Construction Inc	HUNT ELECTRIC SUPPLY CO INC	Unit 3 Turbine Building Grounding Terminations Material
626	132175F000807	WSPM009895	Stone & Webster Construction Inc	HUNT ELECTRIC SUPPLY CO INC	Material for SES Ductbank from Northeast of Diesel to North of Transformer Area
627	132175F000831	WSPM010568	Stone & Webster Construction Inc	HUNT ELECTRIC SUPPLY CO INC	MAB Electrical Supplies
628	132175F000911	WSPM009896	Stone & Webster Construction Inc	HUNT ELECTRIC SUPPLY CO INC	Phase 2 ZFS and ZBS Ductbank Material
629	132175F001430	WSPM009935	Stone & Webster Construction Inc	HUNT ELECTRIC SUPPLY CO INC	Permanent Plant Materials for Systems CWS/RWS duct banks
630	132175F001784	WSPM003592	Stone & Webster Construction Inc	HUNT ELECTRIC SUPPLY CO INC	Washdown Heaters
631	132175F001858	WSPM009824	Stone & Webster Construction Inc	HUNT ELECTRIC SUPPLY CO INC	For use in the NOI 25 tents
632	132175F002950	WSPM010009	Stone & Webster Construction Inc	HUNT ELECTRIC SUPPLY CO INC	Temporary Power Site Wide
633	132175F005259	WSPM004945	WECTEC Global Project Services, Inc.	HUNT ELECTRIC SUPPLY CO INC	Modules Temporary Lighting
634	J132175-C107.02	WSPM009756	Stone & Webster Construction Inc	HYDRO CONDUIT CORP	Reinforced Concrete Pipe|
635	J132175-C107.03	WSPM002189	Stone & Webster Construction Inc	HYDRO CONDUIT CORP	Reinforced Concrete Pipe
636	J132175-C107-01	WSPM002190	Stone & Webster Construction Inc	HYDRO CONDUIT CORP	Reinforced Concrete Pipe Class III, Class V|
637	132175F002278	WSPM010053	Stone & Webster Construction Inc	HYTORC	For Setting WATERBOXES/Temp For Boilers
638	132175F005637	WSPM003630	WECTEC Global Project Services, Inc.	HYTORC	HYTORC TOOLS NEEDED FOR THE CONNECTIONS OF TI4 CONDENSER WATER-BOXES AND ASSOCIATED 120" CROSSOVER PIPING
639	132175F001943	WSPM004444	Stone & Webster Construction Inc	I & I SLING INC	Extension of inspection / certification services for rigging from I&I Slings with additional funds added to BPO 857339
640	132175F002252	WSPM015071	Stone & Webster Construction Inc	I & I SLING INC	Rigging Sling for Modules

641	132175F003694	WSPM004484	Stone & Webster Construction Inc	INDUSTRIAL RUBBER AND SUPPLY	Temporary Material For Flushing The Water Lines
642	132175F001013-REL001	WSPM010112	Stone & Webster Construction Inc	INFORMATION AND COMPUTING SVCS INC	Est. Blanket PO for ICS - Employee Badges not to exceed $80,000 or 2 years
643	132175F001013-REL002	WSPM010484	Stone & Webster Construction Inc	INFORMATION AND COMPUTING SVCS INC	Est. Blanket PO for ICS - Employee Badges not to exceed $80,000 or 2 years
644	132175F001013-REL003	WSPM009978	WECTEC Global Project Services, Inc.	INFORMATION AND COMPUTING SVCS INC	Est. Blanket PO for ICS - Employee Badges not to exceed $80,000 or 2 years
645	132175F004847	WSPM015455	Stone & Webster Construction Inc	INFORMATION AND COMPUTING SVCS INC	Equential Clocks for Operation Needs
646	132175F005110	WSPM004831	WECTEC Global Project Services, Inc.	INFORMATION AND COMPUTING SVCS INC	Ribbon and Cleaner kits for Badge Printers ZXP3 and P120i
647	132175F005724	WSPM004905	WECTEC Global Project Services, Inc.	INTEGRASERV INC	to be used for labeling of received material in warehouse
648	132175F000606	WSPM015391	Stone & Webster Construction Inc	INTERGRAPH SOLUTIONS GROUP	Training for Onsite SEG Civil Eng.
649	132175F002608	WSPM004499	Stone & Webster Construction Inc	INTERGRAPH SOLUTIONS GROUP	GT Strudl Training Courses for Field Rigging Engineers
650	WVG3001144	WVG3001144	WECTEC Global Project Services, Inc.	INTERTEK TECHINCAL SERVICES INC	Module - 3rd Party Inspection / Labor Surveillance
651	132175F005721	WSPM004906	WECTEC Global Project Services, Inc.	JACKIE B LOVETT TRUCKING CO INC	Payment of invoice for Lovett Trucking
652	WVG3000427	WVG3000427	Stone & Webster Construction Inc	JACKIE B LOVETT TRUCKING CO INC	Premium for Excess Liability Insurance Coverage - Jackie B. Lovett Trucking Co. Inc
653	700135-3M	WSPM004316	Stone & Webster Construction Inc	JANPRO OF SOUTHEAST GEORGIA	Extend PO700135 Jan Pro, add additional funding and not to exceed order
654	132175F002514	WSPM010192	Stone & Webster Construction Inc	L B FOSTER RAIL TECHNOLOGIES CORP	HLD Rail Lubricant
655	WVG3000966	WVG3000966	Stone & Webster Construction Inc	LAKESIDE REFRIGERATION	Lakeside Refrigeration Services
656	132175F000815	WSPM010566	Stone & Webster Construction Inc	LANDRUM SUPPLY CO	TEMPORARY CONSTRUCTION - Lift Station Pump
657	132175F001090	WSPM009869	Stone & Webster Construction Inc	LANDRUM SUPPLY CO	TEMPORARY CONSTRUCTION - Batch Plant Condensate Pumps
658	132175F001990	WSPM010164	Stone & Webster Construction Inc	LANDRUM SUPPLY CO	TEMPORARY CONSTRUCTION - Sump Pumps

659	132175F004104	WSPM010637	Stone & Webster Construction Inc	LANDRUM SUPPLY CO	Construction Aid - BOP Plumbers
660	132175F004922	WSPM009893	WECTEC Global Project Services, Inc.	LANDRUM SUPPLY CO	Temporary Construction - Building 304 Plumbing
661	132175F005095	WSPM009976	WECTEC Global Project Services, Inc.	LANDRUM SUPPLY CO	Temporary Construction Aid - Building 304 Plumbing
662	132175F005523	WSPM009750	WECTEC Global Project Services, Inc.	LANDRUM SUPPLY CO	Temporary Construction - BOP - Plumbing - 120 building/Batch Plant
663	132175F005689	WSPM004888	WECTEC Global Project Services, Inc.	LANDRUM SUPPLY CO	Temporary Construction - BOP Plumbing & Testing
664	132175F005896	WSPM010136	WECTEC Global Project Services, Inc.	LANDRUM SUPPLY CO	Temporary Construction - BOP - Batch Plant - Ice House and Demin Skid
665	132175F005940	WSPM002998	WECTEC Global Project Services, Inc.	LANDRUM SUPPLY CO	Temporary Construction - Grinder Pump - Sanitary Sewer
666	132175F005952	WSPM010197	WECTEC Global Project Services, Inc.	LANDRUM SUPPLY CO	Temporary Construction - BOP - Plumbing for Site Restrooms
667	132175F006082	WSPM010214	WECTEC Global Project Services, Inc.	LANDRUM SUPPLY CO	Temporary Construction - Plumbing for BOP
668	WVG3000714	WVG3000714	WECTEC Global Project Services, Inc.	LANDRUM SUPPLY CO	BOP TEMPORARY CONSTRUCTION AID FOR USE AT 129 Bathroom Trailer
669	132175-C202A	WSPM003274	Stone & Webster Construction Inc	LANIER MUNICIPAL SUPPLY CO INC	Yard Fire System Valves
670	132175F005409	WSPM003575	WECTEC Global Project Services, Inc.	LEICA GEOSYSTEMS INC	Site Survey Support
671	4500715839	4500715839	WECTEC Contractors Inc	LEICA GEOSYSTEMS INC	PARTS
672	132175F000532	WSPM004563	Stone & Webster Construction Inc	LIFTING GEAR HIRE CORP	Skid Pan - Scaffolds
673	132175F000782	WSPM009868	Stone & Webster Construction Inc	LIFTING GEAR HIRE CORP	(3) Skip Pans for Unit 3, Jim Schaible
674	132175F003082	WSPM004467	Stone & Webster Construction Inc	LIFTING GEAR HIRE CORP	Skip Pans for Annex and Transformer Unit 3
675	132175F003124	WSPM004477	Stone & Webster Construction Inc	LIFTING GEAR HIRE CORP	Removing Elevated Scrap Trash/Waste During Construction Davis/Peel
676	132175F005654	WSPM014720	WECTEC Global Project Services, Inc.	LIFTING GEAR HIRE CORP	Rental equipment for CA03 Installation, work package SV3-CA03-MHH-005
677	WVG3000737	WVG3000737	Stone & Webster Construction Inc	LIFTING GEAR HIRE CORP	Rental of air skate load module system, steel gantries and

					associated rigging equipment to be used for skidding the (8) CWS pumps into bldg 184
678	132175-D800.03	WSPM003366	WECTEC Global Project Services, Inc.	LIGHTNING LIFT PRODUCTS	Portable Scissor Lift
680	WVG4001238	WVG4001238	WECTEC Global Project Services, Inc.	LINCOLN STRUCTURAL SOLUTIONS	Material to be left in place and used for installation of TB05 (CA81) for Unit 4 Turbine building, work package SV4-2050-SSW-CV1823
681	WVG3000122	WVG3000122	Stone & Webster Construction Inc	LINE EQUIPMENT SALES CO INC	Electrical PPE Testing - Line Equipment Sales - NTE $2,500.00
682	132175F001286	WSPM004610	Stone & Webster Construction Inc	LOWE SPECIALIZED TRANSPORT LLC	TRAILERS
683	132175F002837	WSPM004416	Stone & Webster Construction Inc	LOWE SPECIALIZED TRANSPORT LLC	FLATBED TRAILERS MUST BE DOT READY-FOR WAREHOUSE ISSUING-DURATION OF 24 MONTHS
684	132175-PY30.02	WSPM000107	WECTEC Global Project Services, Inc.	MACKSON INC	Single Stage Orifice Plate (PY30) for Various NSR Applications
685	132175-PY31.01	WSPM000106	WECTEC Global Project Services, Inc.	MACKSON INC	Multi-Stage Orifices (PY31) for Various NSR Applications
686	132176-PY30.02	WSPM000837	WECTEC Global Project Services, Inc.	MACKSON INC	Single Stage Orifice Plate (PY30) for Various NSR Applications
687	132176-PY31.01	WSPM000836	WECTEC Global Project Services, Inc.	MACKSON INC	Multi-Stage Orifices (PY31) for Various NSR Applications
688	WSV3B00038	WSV3B00038	WECTEC Global Project Services, Inc.	MACKSON INC	B31.1 Bolts Safety Class D - Blanket Order Release
689	132175-SS01.48	WSPM010856	WECTEC Global Project Services, Inc.	MACKSON NUCLEAR LLC	Structural Steel Materials for Anchor Plate Fabrication
690	4500675740	4500675740	Westinghouse Electric Company LLC	MANGIAROTTI SpA	Instrumented Cover Invoicing
691	132175F005485	WSPM004900	WECTEC Global Project Services, Inc.	MAR COR PURIFICATION INC	Water Quality lab no bldg no# PM temp.const. activity. mar cor polisher sys. for sampling- parts, Installation service “as ordered for VC Summer 132177F010401 “
692	132175F005578	WSPM004948	WECTEC Global Project Services, Inc.	MAR COR PURIFICATION INC	Faucet-PVC 3/8” Deck Mount by Mar Cor to be used w/ DI Polishing system for the water Quality Lab
693	132175F005861	WSPM004709	WECTEC Global Project Services, Inc.	MAR COR PURIFICATION INC	UV Disinfection unit for the DI Polishing system for Water Quality Lab vendor will install on site .

CONFIDENTIAL& PROPRIETARY
CONFIDENTIAL TRADE SECRET INFORMATION

694	132175F000245	WSPM003726	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	#57 Stone to be used as construction aid material for bedding, backfill and leveling of manholes and duct bank associated with Phase 1 undergrounds-Work Package SV3-ECS-CCW-CV1902
695	132175F000352-004-REL	WSPM009876	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	GABC Stone for site support, Blanket Order, Rick Prohaska, 132175F000352 Release 4
696	132175F000352-005-REL	WSPM009878	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
697	132175F000352-006-REL	WSPM009881	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
698	132175F000352-007-REL	WSPM009988	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
699	132175F000352-008-REL	WSPM009990	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
700	132175F000352-009-REL	WSPM009939	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
701	132175F000352-010-REL	WSPM009768	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
702	132175F000352-011-REL	WSPM009773	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
703	132175F000352-012-REL	WSPM009776	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
704	132175F000352-013-REL	WSPM009825	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
705	132175F000352-014-REL	WSPM009839	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
706	132175F000352-015-REL	WSPM010167	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
707	132175F000352-016-REL	WSPM010173	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
708	132175F000352-017-REL	WSPM010177	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
709	132175F000352-020-REL	WSPM010181	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration

710	132175F000352-021-REL	WSPM010047	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
711	132175F000352-022-REL	WSPM010057	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration

712	132175F000352-023-REL	WSPM010021	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
713	132175F000352-024-REL	WSPM010004	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
714	132175F000352-025-REL	WSPM010008	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
715	132175F000352-026-REL	WSPM010099	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
716	132175F000352-027-REL	WSPM010100	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
717	132175F000352-028-REL	WSPM010101	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
718	132175F000352-029-REL	WSPM010106	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
719	132175F000352-030-REL	WSPM010060	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
720	132175F000352-031-REL	WSPM010065	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
721	132175F000352-032-REL	WSPM010357	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
722	132175F000352-033-REL	WSPM010359	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
723	132175F000352-034-REL	WSPM010360	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
724	132175F000352-035-REL	WSPM010362	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
725	132175F000352-036-REL	WSPM010366	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
726	132175F000352-037-REL	WSPM010370	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
727	132175F000352-038-REL	WSPM010371	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
728	132175F000352-039-REL	WSPM010373	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
729	132175F000352-040-REL	WSPM010439	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
730	132175F000352-041-REL	WSPM010274	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
731	132175F000352-042-REL	WSPM010282	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration

732	132175F000352-043-REL	WSPM010283	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
733	132175F000352-044-REL	WSPM010285	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
734	132175F000352-045-REL	WSPM010622	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
735	132175F000352-046-REL	WSPM010636	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
736	132175F000352-047-REL	WSPM010639	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
737	132175F000352-048-REL	WSPM010650	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
738	132175F000352-049-REL	WSPM010652	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
739	132175F000352-050-REL	WSPM010654	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
740	132175F000352-051-REL	WSPM003722	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
741	132175F000352-052-REL	WSPM010537	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
742	132175F000352-053-REL	WSPM009983	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
743	132175F000352-055-REL	WSPM009855	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
744	132175F000352-056-REL	WSPM009856	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
745	132175F000352-058-REL	WSPM009787	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
746	132175F000352-059-REL	WSPM009790	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
747	132175F000352-061-REL	WSPM010140	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
748	132175F000352-062-REL	WSPM010207	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
749	132175F000929	WSPM004630	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	NOI 25 - GABC Additional Laydown
750	132175F00352-019-REL	WSPM003708	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
751	132175F005521	WSPM003566	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	GAB for Building 305, Rick Prohaska
752	J132175-FPR13-00148	WSPM002115	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Aggregate - Road Base

753	J132175-FPR13-00547	WSPM004372	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Aggregate - Road Base
754	J132175-FPR13-00597	WSPM004373	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	GABC - Aggregate - Road Base
755	J132175-FPR13-00657	WSPM004374	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Aggregate #57 Stone
756	J132175-FPR14-00048	WSPM002108	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Aggregate - #57 Stone
757	J1321760003-FPR124-00017	WSPM002275	Stone & Webster Construction Inc	MARTIN MARIETTA MATERIALS	Crusher Run - No Particles Greater Than 1-1/2” - Per GDOT Section 815,
758	WVG3000039	WVG3000039	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	#57 stone for BOP-Cable Trench Sys & FPS backfill, F000245-REL021
759	WVG3000095	WVG3000095	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	GABC - 132175F000352-063-REL
760	WVG3000126	WVG3000126	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	Blanket Order for GAB - 132175F000352-REL 064
761	WVG3000285	WVG3000285	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	Blanket Order for GAB (132175F000352-REL065)
762	WVG3000386	WVG3000386	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	#57 stone to be used for site support, Rick Prohaska, 132175F000245
763	WVG3000387	WVG3000387	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
764	WVG3000526	WVG3000526	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
765	WVG3000723	WVG3000723	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration
766	WVG3000884	WVG3000884	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	57 stone for site support-utility installation, 132175F000245Rick Prohaska
767	WVG3001126	WVG3001126	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	Blanket Order F000352 REL 069 for GAB for project duration
768	WVG3001129	WVG3001129	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	Blanket Order F000352 REL 070 for GAB for project duration
769	WVG3001354	WVG3001354	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	#57 stone for SES/Security Infrastructure installation, blanket order, Rick Prohaska, 132175F000245

770	WVG3001447	WVG3001447	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	Blanket Order F000352 REL 071 for GAB for project duration
771	WVG3001535	WVG3001535	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	REL 072 to "Blanket Order" 132175F000352 for GAB for project duration
772	WVG3001694	WVG3001694	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	#57 stone for phased underground utility installation, Rick Prohaska, BPO 132175F000245 REL 025 WVG3001694
773	WVG3001733	WVG3001733	WECTEC Global Project Services, Inc.	MARTIN MARIETTA MATERIALS	Blanket Order for GAB for project duration 132175F000352 REL 073
774	WVG3000738	WVG3000738	Stone & Webster Construction Inc	MATHESON TRI GAS INC	Matheson Tri Gas Transferring JDE PO 801955-3P to SPMAT
775	WVG3000740	WVG3000740	WECTEC Global Project Services, Inc.	MATHESON TRI GAS INC	Open funds from F000365 transfer to new PO (Air Liquide to Matheson Tri Gas)
776	WVG300738A	WVG300738A	Stone & Webster Construction Inc	MATHESON TRI GAS INC	Matheson Tri Gas Transferring JDE PO 801955-3P to
777	132175-MH40.01	WSPM003996	Stone & Webster Construction Inc	MAZZELLA LIFTING TECHNOLOGIES INC	MH40 Monorail Hoists and Trolleys
778	132176-MH40.01	WSPM003992	Stone & Webster Construction Inc	MAZZELLA LIFTING TECHNOLOGIES INC	MH40 Monorail Hoists and Trolleys
779	WVG3000030	WVG3000030	WECTEC Global Project Services, Inc.	MAZZELLA LIFTING TECHNOLOGIES INC	equipment to be used for general rigging in the MAB-needed for CA01-07 upending, work package SV4-CA01-MHH-023
780	WVG3000249	WVG3000249	WECTEC Global Project Services, Inc.	MAZZELLA LIFTING TECHNOLOGIES INC	Equipment to be used for offloading materials at the 322 and 307 bldgs to supports RMS and PMS equipment
781	WVG3000849	WVG3000849	WECTEC Global Project Services, Inc.	MAZZELLA LIFTING TECHNOLOGIES INC	CRANE CABLE - 28MM DY34 MAX RLANG HPTP X 3050' FOR MANITIWOC 16000 CRAWLER
782	132175F005536	WSPM004939	WECTEC Global Project Services, Inc.	MCDONOUGH CONSTRUCTION RENTALS INC	2 YEAR RENTAL - CONSTRUCTION ELEVATOR INSTALLED EAST SIDE OF TI3 & TI 4 BETWEEN COLUMNS 13-14 FOR PERSONAL & EQUIPMENT TRANSPORTATION
783	132175F002436	WSPM004409	Stone & Webster Construction Inc	MCGINTY GORDON & ASSOCIATES	Southeastern Rail Consulting Insurnace Renewal for 2014-2015

784	132175-C121.03	WSPM010305	Stone & Webster Construction Inc	MRC GLOBAL US INC	Transformer Pad Pipes and Caps
785	132175-C121.13	WSPM010061	Stone & Webster Construction Inc	MRC GLOBAL US INC	Casing Piping for PWS and YFS for Building 303
786	132175F001738	WSPM009850	Stone & Webster Construction Inc	MRC GLOBAL US INC	*URGENT* PIPE CAPS
787	132175F001782	WSPM011020	Stone & Webster Construction Inc	MRC GLOBAL US INC	Temporary Construction - Plumbing/Compressed Air
788	132175F003698	WSPM011061	Stone & Webster Construction Inc	MRC GLOBAL US INC	Construction Aid
789	132175F005184	WSPM009944	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	Temporary Construction - Plumbing
790	132175F005195	WSPM009946	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	Temporary Construction - BOP Testing
791	132175F005268	WSPM009725	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	Temporary Construction Aid - BOP Plumbing
792	132175F005544	WSPM009754	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	Nonpermanent Plant Material For Testing Purposes. NI3 Pipefitters.
793	132175F005581	WSPM009854	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	Temporary Construction Grinder Pump Material Building 120 Restrooms
794	WVG3000059	WVG3000059	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	caps and plugs for material storage at the warehouse
795	WVG3000353	WVG3000353	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	Hot Item Please Expedite If Possible. Plugs for CA20 attachment brackets. FME. Nonpermanent Plant.
796	WVG3001128	WVG3001128	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	BOP CONSTRUCTION AID
797	WVG3001243	WVG3001243	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	Temporary Construction Aid for Dewatering on Entire Site
798	WVG3001269	WVG3001269	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	BOP TEMPORARY CONSTRCTION AID MATERIAL
799	132175-C913B.01	WSPM003263	Stone & Webster Construction Inc	MRC GLOBAL US INC	Underground Pipe Casings
800	132175-PL03.02	WSPM010461	Stone & Webster Construction Inc	MRC GLOBAL US INC	Victaulic Piping for CAS System
801	132176-PL03.02	WSPM010462	Stone & Webster Construction Inc	MRC GLOBAL US INC	Victaulic Piping for CAS System
802	WVG3001382	WVG3001382	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	TI3 PIPE - FOR TEMP ARGON HEADER - DANNY TAPLEY PTT 154

803	WVG3001391	WVG3001391	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	BOP TEMPORARY CONSTRUCTION AID FOR UNIT RESTROOMS ON THE ENTIRE SITE
804	WVG3001392	WVG3001392	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	BOP TEMPORARY CONSTRUCTION AID FOR BATHRROM/ ICEHOUSE/& BATCH PLANT
805	WVG3001397	WVG3001397	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	(IHP) Integrated Head Package FME Covers
806	WVG3001451	WVG3001451	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	TI3 PIPE TEMP ARGON HEADER DANNY PTT 154/TREY PTT 910
807	WVG3001468	WVG3001468	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	TI3 SS FITTINGS TEMP ARGON HEADER. DANNY TAPLEY PTT 154 / TREY PTT 910
808	132175F004416	WSPM004862	Stone & Webster Construction Inc	MCMASTER CARR SUPPLY CO	Safeguards Area
809	132175-FPR14-00247	WSPM006980	Stone & Webster Construction Inc	MERRILLS INVESTIGATIONS	Drug Detection by Canine
810	132175F005807	WSPM003011	WECTEC Global Project Services, Inc.	MFE RENTALS INC	Hardness Tester, Krautkramer MIC 10
811	132175F000369	WSPM010532	Stone & Webster Construction Inc	MID AMERICA POWERED VEHICLES CORP	CLUB CAR XRT950 PARTS
812	WVG3001249	WVG3001249	Stone & Webster Construction Inc	MID SOUTH LUMBER CO	Lumber for Construction Aids for Unit 4 Annex
813	132176-MS90.01	WSPM000919	Stone & Webster Construction Inc	MILTON CAT	Ancillary Diesel Generators
814	132175F000699	WSPM004640	Stone & Webster Construction Inc	MOBILE MINI INC	(2) Conex's for Rebar Bender Area
815	WVG3000162	WVG3000162	Stone & Webster Construction Inc	MOBILE MINI INC	BPO to Cover All New and Existing Mobile Minis
816	132175F000530	WSPM010587	Stone & Webster Construction Inc	MODERN BUSINESS	Modern Business Items Needed until Blanket PO is placed in SmartPlant
817	132175F000576-REL001	WSPM004636	Stone & Webster Construction Inc	MODERN BUSINESS	Modern Business - Est. Blanket PO in Smart Plant Replace old JDE PO 878886-3P
818	132175F000576-REL002	WSPM004637	Stone & Webster Construction Inc	MODERN BUSINESS	Modern Business - Est. Blanket PO in Smart Plant Replace old JDE PO 878886-3P

819	132175F000576-REL004	WSPM010048	Stone & Webster Construction Inc	MODERN BUSINESS	Modern Business - Est. Blanket PO in Smart Plant Replace old JDE PO 878886-3P
820	132175F000576-REL012	WSPM010480	Stone & Webster Construction Inc	MODERN BUSINESS	Modern Business - Est. Blanket PO in Smart Plant Replace old JDE PO 878886-3P
821	132175F005778	WSPM004913	WECTEC Global Project Services, Inc.	MODERN BUSINESS	office furniture
822	132175F005871-B	WSPM004710	WECTEC Global Project Services, Inc.	MODERN BUSINESS	Consumables
823	WVG3000116	WVG3000116	Stone & Webster Construction Inc	MODERN BUSINESS	Modern Business - 132175F000576-REL019
824	WVG3000259	WVG3000259	Stone & Webster Construction Inc	MODERN BUSINESS	BPO 132175F000576 Marker Boards
825	WVG3000485	WVG3000485	Stone & Webster Construction Inc	MODERN BUSINESS	124 War Room
826	WVG3000636	WVG3000636	Stone & Webster Construction Inc	MODERN BUSINESS	Modern Business - Est. Blanket PO in Smart Plant Replace old JDE PO 878886-3P
827	WVG3000706	WVG3000706	Stone & Webster Construction Inc	MODERN BUSINESS	Stackable Chairs for RM 4 @ Tobacco Road
828	132175F004321	WSPM004810	Stone & Webster Construction Inc	MODSPACE	Building 165A
829	132175F001451	WSPM010001	Stone & Webster Construction Inc	MOORE MEDICAL LLC	Medical Supplies from MooreMedical
830	132175F001502	WSPM004600	Stone & Webster Construction Inc	MOORE MEDICAL LLC	Medical Supplies from Moore Medical (2)
831	J132175-FPR14-00040	WSPM013574	Stone & Webster Construction Inc	MORRIS AND ASSOCIATES INC	Professional Services Agreement
832	132175F004372	WSPM015080	Stone & Webster Construction Inc	MR GOLF CARTS INC	Golf chart for Dan Elder, Weld Training. 1 month rental.
833	WVG3000156	WVG3000156	Stone & Webster Construction Inc	MR GOLF CARTS INC	BPO to Cover All New and Existing Mr. Golf Cart Rentals
834	132175-C121.15	WSPM015662	Stone & Webster Construction Inc	MRC GLOBAL US INC	Miscellaneous Pipe and Fittings for U/G Phase 3 and 8 CWS, and Building 315 PWS and RWS
835	132175F001135	WSPM012071	Stone & Webster Construction Inc	MRC GLOBAL US INC	Modification of Grout Pump Outlet
836	132175F001241	WSPM012072	Stone & Webster Construction Inc	MRC GLOBAL US INC	PIPE CAPS
837	132175F002994	WSPM015232	Stone & Webster Construction Inc	MRC GLOBAL US INC	Non-safety, temporary material for Hydro on the mechanical modules

838	132175F004324	WSPM012133	Stone & Webster Construction Inc	MRC GLOBAL US INC	Temporary Construction Aid - BOP - Plumbing
839	132175F005276	WSPM015669	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	Temporary Construction-Plumbing-BOP
840	132175F005323	WSPM015670	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	Temporary Construction - BOP Plumbing - Building 120
841	132175F005693	WSPM011313	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	Temporary Construction - BOP - Batch Plant Valves
842	WVG3000383	WVG3000383	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	Material for 184 Valve Recovery
843	WVG3000703	WVG3000703	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	BOP/PLUMBING,TESTING/BATCH PLANT/ ICE HOUSE
844	WVG3000833	WVG3000833	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	TEMP. FIRE PROTECTION SYSTEM-TURBINE#4
845	WVG3001024	WVG3001024	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	TUBING -PVC CLEAR VINYL FOR TI#3 CARPENTERS
846	WVG3001267	WVG3001267	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	Material to be left in place and used for welded cable tray supports, wok package SV3-2039-SHW-860272
847	WVG3001496	WVG3001496	WECTEC Global Project Services, Inc.	MRC GLOBAL US INC	BOP TEMPORARY CONSTRUCTION AID MATERIAL FOR HYDRO TESTING
848	132175F000968	WSPM004626	Stone & Webster Construction Inc	MSC INDUSTRIAL SUPPLY CO INC (PA &	Batch Plant - Limit Switches for Ice House
849	132175F005240	WSPM009963	WECTEC Global Project Services, Inc.	MSC INDUSTRIAL SUPPLY CO INC (PA &	Drum Plug Socket
850	WVG3000630	WVG3000630	WECTEC Global Project Services, Inc.	MULTISCOPE DOCUMENT SOLUTIONS INC	New printers to be used for Vogtle Construction Support Buildings.
851	132175-C121.08	WSPM013218	Stone & Webster Construction Inc	MUNS SERVICES LLC	WWS Piping for the Transformer Area - Phase 2 Construction
852	132175-C904.01	WSPM015092	Stone & Webster Construction Inc	MURRAY SUPPLY CO LLC	Standard Plant Equipment & Floor Drains
853	132175-C904.02	WSPM004586	Stone & Webster Construction Inc	MURRAY SUPPLY CO LLC	Floor and Equipment Drain Screws and Drains
854	132175-PV50.02	WSPM011812	WECTEC Global Project Services, Inc.	MURRAY SUPPLY CO LLC	PV50.02 - NFPA Code Valves (NS)
855	132175-PV50.03	WSPM000110	WECTEC Global Project Services, Inc.	MURRAY SUPPLY CO LLC	NFPA Code Valves (Datasheets PV50-Z0D-130, 132, 134, 136, 138)

856	132176-MB70.00	WSPM003934	Stone & Webster Construction Inc	MURRAY SUPPLY CO LLC	MB70 - Hot Water Heaters
857	132176-PV50.02	WSPM011686	WECTEC Global Project Services, Inc.	MURRAY SUPPLY CO LLC	PV50.02 - NFPA Code Valves (NS)
858	132176-PV50.03	WSPM000841	WECTEC Global Project Services, Inc.	MURRAY SUPPLY CO LLC	NFPA Code Valves
863	132175F004959	WSPM009884	WECTEC Global Project Services, Inc.	NELSON STUD WELDING INC	Equipment for thur decking stud welding
864	WVG3000213	WVG3000213	WECTEC Global Project Services, Inc.	NELSON STUD WELDING INC	ANNEX 3 NELSON TOOLS TO BE USED ON HILTI GIRDER SUP STEEL WELD STUDS WPSV3-2053-SHW-EL7841
865	WVG3000214	WVG3000214	WECTEC Global Project Services, Inc.	NELSON STUD WELDING INC	TURBINE 3 NELSON TOOLS TO BE USED ON HILTI MI-120 GIRDER SUP STEEL WP SV3-2052-SHW-860953
866	WVG3000255	WVG3000255	Stone & Webster Construction Inc	NELSON STUD WELDING INC	ANNEX 3 NELSON TOOLS TO BE USED ON HILTI MI-120 GIRDER SUP STEEL SV3-2053-SHW-EL7841
867	132175F005842	WSPM010216	WECTEC Global Project Services, Inc.	NEW PIG CORPORATION	Environmental Spill Supplies
868	WVG3000284	WVG3000284	WECTEC Global Project Services, Inc.	NEW PIG CORPORATION	HSE - Environmental Spill Supplies
869	WVG3000535	WVG3000535	WECTEC Global Project Services, Inc.	NEW PIG CORPORATION	HSE - Environmental - New Pig Supplies
870	WVG3000996	WVG3000996	Stone & Webster Construction Inc	NEW PIG CORPORATION	Material to be used for spills at the warehouse
871	WVG3001330	WVG3001330	WECTEC Global Project Services, Inc.	NEWCO INC	PT Kits for Module Welding
872	132175F000524	WSPM010176	Stone & Webster Construction Inc	NORTON SANDBLASTING EQUIPMENT	PAINT BOOTH
873	132175F004269	WSPM004869	Stone & Webster Construction Inc	NORTON SANDBLASTING EQUIPMENT	Van Air Blast Pak FD-400 Air Dryer, Bernie Wiggington, Paint Shop. 3 years rental.
874	132175-ER01.01	WSPM002958	Stone & Webster Construction Inc	NOVA MACHINE PRODUCTS CORP	Cable Tray and Fittings
875	132175-ER01.05	WSPM002960	Stone & Webster Construction Inc	NOVA MACHINE PRODUCTS CORP	Class 1E Cable Tray and Fittings

876	132175F005710	WSPM000272	WECTEC Global Project Services, Inc.	NOVA MACHINE PRODUCTS CORP	Material to be left in place and used to replace hardware that has been damaged or removed and to be used as surplus. Work package SV3-2060-SUW-CV0193
877	132176-C811.04	WSPM008009	WECTEC Global Project Services, Inc.	NOVA MACHINE PRODUCTS CORP	Replacement Gaskets for Condenser Waterbox
878	132176-D500.31	WSPM003197	Stone & Webster Construction Inc	NOVA MACHINE PRODUCTS CORP	Washers For CA04 Unit 4 Source Range Detectors
879	132176-ER01.01	WSPM003104	Stone & Webster Construction Inc	NOVA MACHINE PRODUCTS CORP	Cable Tray and Fittings
880	132176-ER01.05	WSPM003959	Stone & Webster Construction Inc	NOVA MACHINE PRODUCTS CORP	Class 1E Cable Tray and Fittings
881	132175F001317	WSPM005463	Stone & Webster Construction Inc	OCCUPATIONAL HEALTH AND DYNAMICS	DoseBadge Dosimeter Annual Calibration & Reader Calibration
882	WVG3000860	WVG3000860	WECTEC Global Project Services, Inc.	OCCUPATIONAL HEALTH AND DYNAMICS	HSE/IH - OHD doseBadge Noise Dosimeter Annual Calibration
883	WVG3000050	WVG3000050	WECTEC Global Project Services, Inc.	OFFICE FURNITURE WAREHOUSE OF PITTS	Bldg. 171
884	J132175-J500.01	WSPM002102	Stone & Webster Construction Inc	OLDCASTLE PRECAST	Precast Manholes and Trenches for RWS Well Water Bldg 315|
885	132175-J500.07	WSPM003746	Stone & Webster Construction Inc	OLDCASTLE PRECAST INC	Cooling Tower Precast Drop Inlets
886	J132175-J500.04	WSPM009785	Stone & Webster Construction Inc	OLDCASTLE PRECAST INC	Precast Drop Inlet
887	J132175-J500-01	WSPM002103	Stone & Webster Construction Inc	OLDCASTLE PRECAST INC	Precast Drop Inlet|
888	132175F001025	WSPM004624	Stone & Webster Construction Inc	PAC-VAN INC	Storage at NI 3 for Steve Wallace
889	132175F001122	WSPM004618	Stone & Webster Construction Inc	PAC-VAN INC	Connex’s for Preventive Maintenance Group Storage Supplies
890	132175F001585	WSPM004425	Stone & Webster Construction Inc	PAC-VAN INC	Steve Scott Storage Conexes
891	132175F001908-A	WSPM004447	Stone & Webster Construction Inc	PAC-VAN INC	NO17 module fabrication
892	WVG3000163	WVG3000163	Stone & Webster Construction	PAC-VAN INC	

			Inc		BPO to Cover All New and Existing PacVans
893	132175F004865	WSPM005011	WECTEC Global Project Services, Inc.	PANNIER CORP	Pannier Service Repair PM labeling Embossing equipment

894	132175F005646	WSPM004884	WECTEC Global Project Services, Inc.	PARTNERS IN LEADERSHIP LLC	Two day self tracking training: The Oz Principle Accountability Training Integration Meeting at Plant Vogtle 3 & 4
895	132175-C717A-00	WSPM003267	Stone & Webster Construction Inc	PATTERSON PUMP CO	Fire Pump Skids
896	4500654771	4500654771	Westinghouse Electric Company LLC	PCR HOLDINGS INC	Weight Equivalency Cacl. for SB
897	Lease	Lease	Wectec LLC	Peach Orchard Center, LLC	2215 Tobacco Rd, Augusta GA, 30906-8111
898	132175F003651	WSPM010696	Stone & Webster Construction Inc	PEDRICK TOOL AND MACHINE CO INC	Equipment
899	132175F001815	WSPM004455	Stone & Webster Construction Inc	PENN TOOL	Batch Plant - Grease fittings for trucks
900	132175F001894	WSPM003514	Stone & Webster Construction Inc	PENN TOOL	#4400 WO GRUBB 16000 SERVICE FILTERS
901	132175F003099	WSPM004465	Stone & Webster Construction Inc	PENN TOOL	Lloyd's of London to witness the proof load test of (2) Enerpac 400Te pull cylinders and (1) Enerpac 800Te pull cylinder
902	132175F003334	WSPM010446	Stone & Webster Construction Inc	PENN TOOL	MAB Safety Harness Storage
903	132175F003463	WSPM010618	Stone & Webster Construction Inc	PENN TOOL	FME Cabinets for Module ASME Piping
904	132175F003786	WSPM011989	Stone & Webster Construction Inc	PENN TOOL	Enerpac open PO to allow field services, maintenance and training activities
905	132175F003973	WSPM004845	Stone & Webster Construction Inc	PENN TOOL	To replace load cell connectors on the EVO-W units, in connection with 132175F003786
906	132175F004268	WSPM003331	Stone & Webster Construction Inc	PENN TOOL	Repair and re-load test jacks
907	132175F004684	WSPM009925	WECTEC Global Project Services, Inc.	PENN TOOL	Temporary Construction Aid - NI3 - Auxilary & Containment Buildings
908	132175F004713	WSPM004916	Stone & Webster Construction Inc	PENN TOOL	CLOSING SEAMS, LEAK PROOFING THE FORM WALLS AT TRANSFORMER AREA TEMP CONSTRUCTION AID
909	132175F004932	WSPM009888	WECTEC Global Project Services, Inc.	PENN TOOL	Temporary Construction Aid - Civil Required
910	132175F005167	WSPM009967	WECTEC Global Project Services, Inc.	PENN TOOL	Temporary Construction Aid - Water Removal

911	132175F005354	WSPM009807	WECTEC Global Project Services, Inc.	PENN TOOL	SITE SURVEY SUPPORT
912	132175F005501	WSPM004898	WECTEC Global Project Services, Inc.	PENN TOOL	Temporary Construction - NI4 Piping
913	132175F005606	WSPM004881	WECTEC Global Project Services, Inc.	PENN TOOL	Allen-Bradley software for commissioning PLCs
914	WVG3000007	WVG3000007	WECTEC Global Project Services, Inc.	PENN TOOL	Material to be used for temporary use on Unit 3 ductwork for testing and balancing
915	WVG3000861	WVG3000861	Stone & Webster Construction Inc	PENN TOOL	Black Cartridges for Sign Shop
916	WVG3000928	WVG3000928	Stone & Webster Construction Inc	PENN TOOL	Water Line Support Unit 3 & 4
917	132175F000078-A	WSPM010507	Stone & Webster Construction Inc	PENSKE TRUCK LEASING CO LP	TRUCK AND TRAILER TO MOVE MATERIAL FROM PARKING LOT AND NOI7
918	132175F001481	WSPM004602	Stone & Webster Construction Inc	PENSKE TRUCK LEASING CO LP	Replace and Repair Incident Damage to Penske Truck, PO 893675, Unit 100515
919	WVG3000349	WVG3000349	WECTEC Global Project Services, Inc.	PH TOOL LLC	NDE Equipment-UT Calibration Blocks
920	132175F005794	WSPM007121	WECTEC Global Project Services, Inc.	PINNER CLINIC PA	Est. Blanket PO for Pinner Clinic - Medical Reviewing Official MRO - not to exceed $300,000 or 2 years
921	132175F000386	WSPM004651	Stone & Webster Construction Inc	PORTABLE REFRIGERATION STORAGE INC	Change Order to (2) Extend Refrig. Connex from Portable Refrigeration Unit #'s CRLU810767 & CRLU910782, PO 719626 for 24 Months
922	132175F000392	WSPM004650	Stone & Webster Construction Inc	PORTABLE REFRIGERATION STORAGE INC	(3) Refrigeration Connex's for NI 4 Bottom Head for Safety Related Grout Storage
923	132175F001303	WSPM004609	Stone & Webster Construction Inc	PORTABLE REFRIGERATION STORAGE INC	TEMP CONTROLLED CONNEX FOR MEMBRANE STORAGE
924	132175F002839	WSPM004415	Stone & Webster Construction Inc	PORTABLE REFRIGERATION STORAGE INC	Change Order to Extend Rental for 12 months on 20' Refrigerated Conex from Portable Refrigeration Storage PO 685924
925	132175F002917	WSPM004506	Stone & Webster Construction Inc	PORTABLE REFRIGERATION STORAGE INC	Change Order to Extend Rental 12 Months on PO 680016 from Portable Refigeration Storage

926	132175F004965	WSPM009980	WECTEC Global Project Services, Inc.	POWERHOUSE EQUIPMENT AND ENGRNG	2 - RL-50 Portable Boiler room trailers, Concrete group Robert Carr. 4 months rent.
927	132175F000078	WSPM004661	Stone & Webster Construction Inc	PREMIER TRAILER LEASING INC	TRUCK AND TRAILER TO MOVE MATERIAL FROM PARKING LOT AND NOI7
928	132175F000942	WSPM009987	Stone & Webster Construction Inc	PREMIER TRAILER LEASING INC	TRUCKS AND TRAILERS FOR WAREHOUSE
929	WVG3000417	WVG3000417	Stone & Webster Construction Inc	PREMIER TRAILER LEASING INC	TRANSFER OF FUNDS FROM 890968-3P
930	132175F005125	WSPM004833	WECTEC Global Project Services, Inc.	PRIVATE PROFESSIONAL SERVICES INC	Add Funding to PO 831563-000 3P - Private Professional Services Inc not to exceed 3 years or $60,000
931	WVG3000290	WVG3000290	WECTEC Global Project Services, Inc.	PROJECT TIME AND COST HOLDINGS INC	CONSULTANT SERVICES TO BE PERFORMED FROM THE CHARLOTTE OFFICE
932	4500716562	4500716562	WECTEC Contractors Inc	PUBLIC WORKS EQUIPMENT AND SUPPLY	PARTS
934	132175F003273	WSPM010355	Stone & Webster Construction Inc	QUALITY INDUSTRIAL DISTRIBUTION	Batch Plant - Shop Air Fittings
938	132175F003612	WSPM004462	Stone & Webster Construction Inc	REED ICE CO INC	ICE, for site support
939	4500602717	4500602717	Westinghouse Electric Company LLC	REFRIGERATION SALES CORP	Pump,Vacuum,Rotary Vane, w 60Hz Motor
940	132175-K308-01	WSPM009760	Stone & Webster Construction Inc	REGALBROWN INC	Pressure Switch
941	132175F000118	WSPM010685	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Replacement parts - Plant 1 Roller
942	132175F000136	WSPM010686	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Replacement Parts for Wash Pit
943	132175F000451	WSPM010505	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Oil/Air filters for Plants and shop
944	132175F000623	WSPM014140	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Valve parts for plant
945	132175F001732	WSPM009774	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Chute Seals
946	132175F001817	WSPM009823	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Blower filters
947	132175F001835	WSPM009828	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Solenoid Valves for Agg Gates

948	132175F002029	WSPM010163	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Inner and outer seal
949	132175F002151	WSPM004432	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Parts for Plant water meters
950	132175F002871	WSPM004414	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Plant - Glue, Boot, Hold Down Roller
951	132175F002944	WSPM010093	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Belt Wiper, grease fittings
952	132175F002997-001-REL	WSPM010103	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Rexcon (To Establish Blanket PO)
953	132175F002997-003-REL	WSPM010354	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Rexcon (To Establish Blanket PO)
954	132175F002997-007-REL	WSPM010435	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Rexcon (To Establish Blanket PO)
955	132175F002997-008-REL	WSPM010279	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Rexcon (To Establish Blanket PO)
956	132175F002997-009-REL	WSPM010624	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Rexcon (To Establish Blanket PO)
957	132175F002997-010-REL	WSPM010629	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Rexcon (To Establish Blanket PO)
958	132175F002997-011-REL	WSPM010697	Stone & Webster Construction Inc	REXCON LLC	BPO RELEASE 11 - F004144 & F004206
959	132175F002997-012-REL	WSPM010660	Stone & Webster Construction Inc	REXCON LLC	BLANKET RELEASE 12
960	132175F002997-013-REL	WSPM010661	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Rexcon (To Establish Blanket PO)
961	132175F002997-014-REL	WSPM010491	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Rexcon
962	132175F002997-015-REL	WSPM010494	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Rexcon (To Establish Blanket PO)
963	132175F002997-016-REL	WSPM010548	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Rexcon (To Establish Blanket PO)
964	132175F002997-018-REL	WSPM009900	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Rexcon (To Establish Blanket PO)
965	132175F002997-024-REL	WSPM004473	WECTEC Global Project Services, Inc.	REXCON LLC	Batch Plant - Rexcon (To Establish Blanket PO)
966	132175F004490	WSPM010486	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Air Coupling, Jack
967	132175F004605	WSPM010594	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Water Hose, Limit Switch
968	WVG3000193	WVG3000193	Stone & Webster Construction Inc	REXCON LLC	Batch Plant - Rexcon PO 2997 REL

					027 (To Establish Blanket PO)
969	WVG3000511	WVG3000511	WECTEC Global Project Services, Inc.	REXCON LLC	Batch Plant - Rexcon BPO 2997 REL 30
970	WVG3000590	WVG3000590	WECTEC Global Project Services, Inc.	REXCON LLC	5” Butterfly Valves for Batch Plant
971	WVG3000598	WVG3000598	WECTEC Global Project Services, Inc.	REXCON LLC	Batch Plant - Rexcon BPO 2997 REL 31
972	WVG3000609	WVG3000609	WECTEC Global Project Services, Inc.	REXCON LLC	Batch Plant - Rexcon BPO 2997 REL 32
973	WVG3000622	WVG3000622	WECTEC Global Project Services, Inc.	REXCON LLC	Coupling and Gaskets - Batch Plant
974	WVG3000664	WVG3000664	WECTEC Global Project Services, Inc.	REXCON LLC	Batch Plant - Rexcon BPO 2997 REL 33
975	WVG3000867	WVG3000867	WECTEC Global Project Services, Inc.	REXCON LLC	Batch Plant Dust Bag 8”x114”
976	132175F001444	WSPM015657	Stone & Webster Construction Inc	RFID MERGER CORPHOTHEAD TECH INC	HOT Guard Biosensor
977	WVG3001262	WVG3001262	WECTEC Global Project Services, Inc.	RICHMOND SUPPLY CO	to be left in place and used for bldg 315 potable water system chem add skid (SV0-PWS-MS-501), work package SV0-PWS-01-CT001
978	WVG3001428	WVG3001428	WECTEC Global Project Services, Inc.	RICHMOND SUPPLY CO	Material left in place for installation on PWS Jockey Pump, 0-PWS-MP503, suction in place of crack installed instrument, SV0-PWS-01-IT001 (REPLACEMENT)
979	132175-JE02.00	WSPM010131	WECTEC Global Project Services, Inc.	ROSEMOUNT INC	SV0-PWS-JE-FT510 Transmitter Replacement
982	132175-AS20.01	WSPM003324	Stone & Webster Construction Inc	SAFARILAND LLC	Security Equipment - GPs, DFPs, and BREs
983	132176-AS20.01	WSPM002986	Stone & Webster Construction Inc	SAFARILAND LLC	Gun Ports, Defensive Fighting Positions and Bullet Restistant Enclosures.
984	WVG3000734	WVG3000734	Stone & Webster Construction Inc	SAFETY-KLEEN	Rental Parts Washer with Service (Safety-Kleen) Revision to 132175F001923
985	132175F003068	WSPM004468	Stone & Webster Construction Inc	SATELLITE SHELTERS INC	Assuming Lease from SNC for Building 187 to CBI Starting 3-1-15
986	132175F004643	WSPM004840	Stone & Webster Construction Inc	SATELLITE SHELTERS INC	5-Plex for CBI - Paintings and Coatings

987	132175-J300.12	WSPM003799	Stone & Webster Construction Inc	SEFA GROUP INC	Fly Ash for Concrete
988	132175F002881	WSPM010095	Stone & Webster Construction Inc	SERVICE INDUSTRIAL SUPPLY CO	Duct Tape - Nuclear Grade
989	132175-EJ02.01	WSPM010064	Stone & Webster Construction Inc	SHEALY ELECTRICAL WHOLESALERS INC.	Non-Class 1E Junction Boxes
990	132175-EL01.02	WSPM002957	Stone & Webster Construction Inc	SHEALY ELECTRICAL WHOLESALERS INC.	Lighting Controller System & Equipment
991	132175-ER02.01	WSPM010375	Stone & Webster Construction Inc	SHEALY ELECTRICAL WHOLESALERS INC.	Conduit and Fittings
992	132175F001158	WSPM011182	Stone & Webster Construction Inc	SHEALY ELECTRICAL WHOLESALERS INC.	Material for NI 3 Electricians
993	132175F002081	WSPM011184	Stone & Webster Construction Inc	SHEALY ELECTRICAL WHOLESALERS INC.	ITEMS TO PROVIDE TEMPORARY POWER TO THE NORTH END OF TB-4
994	132175F003020	WSPM004470	Stone & Webster Construction Inc	SHEALY ELECTRICAL WHOLESALERS INC.	Temporary Power Site Wide
995	132175-SH21.01	WSPM011173	Stone & Webster Construction Inc	SHEALY ELECTRICAL WHOLESALERS INC.	Cable Tray Supports
996	132176-EJ02.01	WSPM003111	Stone & Webster Construction Inc	SHEALY ELECTRICAL WHOLESALERS INC.	Non Class 1E Junction Boxes
997	132176-ER02.01	WSPM003958	Stone & Webster Construction Inc	SHEALY ELECTRICAL WHOLESALERS INC.	Conduit and Fittings
998	132176-SH21.01	WSPM012195	Stone & Webster Construction Inc	SHEALY ELECTRICAL WHOLESALERS INC.	Cable Tray Supports
999	J132175-E112.05	WSPM002177	Stone & Webster Construction Inc	SHEALY ELECTRICAL WHOLESALERS INC.	Rigid Galvanized Steel Conduit
1000	132175F005642	WSPM009795	WECTEC Global Project Services, Inc.	SHERWIN WILLIAMS	Construction aid material to be used for temporary use for Unit 3 Turbine Building coating of supplemental steel, work package SV3-2053-SHW-EL7843
1001	132175F004072	WSPM003344	Stone & Webster Construction Inc	SIKA CORPORATION	Concrete admixture: Hydration Stabilizer/vertical pumping aid for the batch plant
1002	132175-J300.03B	WSPM003143	Stone & Webster Construction Inc	SIKA CORPORATION	Admixtures for Concrete|
1003	844736-3P	WSPM004363	Stone &	SIKA	

			Webster Construction Inc	CORPORATION	Batch Plant - Add funds to PO # 844736-3P
1004	132175F001653	WSPM004405	Stone & Webster Construction Inc	SILICON STUD WELDING PRODUCTS	REPLACEMENT AND ADDITIONAL STUD WELDING PARTS

1005	714750	WSPM010552	Stone & Webster Construction Inc	SNIDER TIRE INC	Change Order to Add Funds to PO 714750 Snider for material and service
1006	WVG3001537	WVG3001537	WECTEC Global Project Services, Inc.	SNIDER TIRE INC	Replacement Tires for Site Rented Big Red Forklift at WW
1007	132175-AD02.02	WSPM003330	WECTEC Global Project Services, Inc.	SOMMER USA INC	Non-Safety Related Hollow Metal Doors and associated hardware for Vogtle Unit 3
1008	132175-PV38.01	WSPM012094	WECTEC Global Project Services, Inc.	SOUTH CAROLINA FLUID TECH LLC	PV38 Automatic Vent Valves - DS 101
1009	132175-PV38.02	WSPM012095	WECTEC Global Project Services, Inc.	SOUTH CAROLINA FLUID TECH LLC	PV38 Automatic Vent Valves - DS 102
1010	132175-PV38.03	WSPM010347	WECTEC Global Project Services, Inc.	SOUTH CAROLINA FLUID TECH LLC	PV38 Automatic Vent Valves - DS 103
1011	132176-PV38.01	WSPM012142	WECTEC Global Project Services, Inc.	SOUTH CAROLINA FLUID TECH LLC	PV38 Automatic Vent Valves - DS 101
1012	132176-PV38.02	WSPM012143	WECTEC Global Project Services, Inc.	SOUTH CAROLINA FLUID TECH LLC	PV38 Automatic Vent Valves - DS 102
1013	132176-PV38.03	WSPM010350	WECTEC Global Project Services, Inc.	SOUTH CAROLINA FLUID TECH LLC	PV38 Automatic Vent Valves - DS 103
1014	132175F001699	WSPM004401	Stone & Webster Construction Inc	SOUTHEAST COASTAL CONSULTING INC	Add Addtiional Funds ($50K) for PO 735956 Southeastern Rail Consulting
1015	132175F001699A	WSPM004398	WECTEC Global Project Services, Inc.	SOUTHEAST COASTAL CONSULTING INC	Add Addtiional Funds for PO 735956
1016	798815 - 3M	WSPM004357	Stone & Webster Construction Inc	SOUTHERN LINC	PTT SERVICES AND EQUIPMENT
1017	132175-K035A.01	WSPM010157	Stone & Webster Construction Inc	SOUTHWELL CORP	WASTE WATER COMPOSITE SAMPLER
1018	132175F003673	WSPM004483	Stone & Webster Construction Inc	SPIDER SAFETY INC	Load test and inspection on Spider baskets for MAB
1019	132175F003745	WSPM010335	Stone & Webster Construction Inc	SPIDER SAFETY INC	Suspension Brackets, Spider. For MAB Spider baskets.
1020	132175F003798	WSPM010337	Stone & Webster Construction Inc	SPIDER SAFETY INC	Suspension Brackets, Spider. For MAB Spider baskets.
1021	132175F005142	WSPM009984	WECTEC Global Project Services, Inc.	SPIDER SAFETY INC	Scaffold baskets for beta hoist system
1022	132175-PY40.00	WSPM010456	Stone & Webster Construction Inc	SPIRAX SARCO INC	PY40 Steam Traps
1023	132176-PY40.00	WSPM010458	Stone & Webster Construction Inc	SPIRAX SARCO INC	PY40 Steam Traps

1024	132175F000168	WSPM010511	Stone & Webster Construction Inc	SPORTEX APPAREL OF ARIZONA	VEST FOR SUPERVISORS
1025	132175F000179	WSPM010530	Stone & Webster Construction Inc	SPORTEX APPAREL OF ARIZONA	Employee Incentatives
1026	132175F000362	WSPM010498	Stone & Webster Construction Inc	SPORTEX APPAREL OF ARIZONA	Safety Vest
1027	132175F000712	WSPM010558	Stone & Webster Construction Inc	SPORTEX APPAREL OF ARIZONA	Employee Incentatives
1028	132175F000809	WSPM010569	Stone & Webster Construction Inc	SPORTEX APPAREL OF ARIZONA	Safety Vests
1029	132175F000870	WSPM009764	Stone & Webster Construction Inc	SPORTEX APPAREL OF ARIZONA	VEST FOR SUPERVISORS
1030	132175F001081	WSPM009871	Stone & Webster Construction Inc	SPORTEX APPAREL OF ARIZONA	Fire Watch Vest
1031	132175F001655	WSPM009782	Stone & Webster Construction Inc	SPORTEX APPAREL OF ARIZONA	VEST FOR SUPERVISORS
1032	132175F001723	WSPM009783	Stone & Webster Construction Inc	SPORTEX APPAREL OF ARIZONA	Security Safety Vests w/ labeling
1033	132175F002300	WSPM010251	Stone & Webster Construction Inc	SPORTEX APPAREL OF ARIZONA	Vests
1034	132175F002806-REL002	WSPM009903	Stone & Webster Construction Inc	SPORTEX APPAREL OF ARIZONA	Blanket Order for Sportex - Employee Incentatives
1035	132175F003213	WSPM010436	Stone & Webster Construction Inc	SPORTEX APPAREL OF ARIZONA	Security Safety Vests w/ Labeling
1036	132175F003584	WSPM010443	Stone & Webster Construction Inc	SPORTEX APPAREL OF ARIZONA	Safety Committee Vests
1037	132175F004457	WSPM010490	Stone & Webster Construction Inc	SPORTEX APPAREL OF ARIZONA	Sportex - ERT Rescue Bags
1038	132175F005089	WSPM009951	WECTEC Global Project Services, Inc.	SPORTEX APPAREL OF ARIZONA	ERT Vests
1039	WVG3000648	WVG3000648	WECTEC Global Project Services, Inc.	SPORTEX APPAREL OF ARIZONA	HSE-PPE VESTS “HSE/SAFETY” ADDTL SIZES NEEDED
1040	132175-H700.03	WSPM003146	Stone & Webster Construction Inc	SSM INDUSTRIES INC	HVAC Ductwork - CA20, R104, and R161
1041	132175-MA01.00	WSPM003788	Stone & Webster Construction Inc	SSM INDUSTRIES INC	Centrifugal and Propeller Fans
1042	132175-MD01.00	WSPM003787	Stone & Webster Construction Inc	SSM INDUSTRIES INC	Nonsafety-Related Dampers
1043	132176-MA01.00	WSPM003935	Stone & Webster Construction Inc	SSM INDUSTRIES INC	Centrifugal and Propeller Fans

1044	132176-MD01.00	WSPM003933	Stone & Webster Construction Inc	SSM INDUSTRIES INC	Nonsafety-Related Dampers
1045	WVG3001245	WVG3001245	WECTEC Global Project Services, Inc.	SSM INDUSTRIES INC	MATERIAL LEFT IN PLACE ANNEX 3 BENT PLATE CMU WALLS WP# SV3-4030-AMW-850000
1046	132175F005669	WSPM013179	WECTEC Global Project Services, Inc.	STAPLES CONTRACT AND COMMERCIAL	stamp to be used for the ITAAC group to retrofit ITAAC screening forms of 750 work packages to satisfy CAR 2016-1916
1047	132175F005790	WSPM013177	WECTEC Global Project Services, Inc.	STAPLES CONTRACT AND COMMERCIAL	To be used for the Welding Departmental Printers to generate weld data sheets for project construction
1048	4500645824	4500645824	Westinghouse Electric Company LLC	STEVENSON & ASSOCIATES	Vogtle Option 3
1049	132175-J800.14	WSPM003794	Stone & Webster Construction Inc	STIRLING LLOYD PRODUCTS INC	Nuclear Island Waterproofing Membrane Material|
1050	WVG3000168	WVG3000168	WECTEC Global Project Services, Inc.	STRAIGHTPOINT INC	Recalibration and repair of load cells for general site use
1051	132175-PY02.00	WSPM010258	Stone & Webster Construction Inc	SURE FLOW EQUIPMENT INC	Inline Piping Strainers, ANSI/ASME B31.1
1052	132175-PY03.00	WSPM010301	Stone & Webster Construction Inc	SURE FLOW EQUIPMENT INC	Inline Piping Temporary Strainers ASME B31.1
1053	132176-PY02.00	WSPM010259	Stone & Webster Construction Inc	SURE FLOW EQUIPMENT INC	Inline Piping Strainers, ANSI/ASME B31.1
1054	132176-PY03.00	WSPM010302	Stone & Webster Construction Inc	SURE FLOW EQUIPMENT INC	Inline Piping Temporary Strainers ASME B31.1
1055	Lease	Lease	Wectec LLC	Synergy Group, LLC	321 Mills Road, Waynesboro, GA, 30830
1056	132175-EY20.01	WSPM003152	Stone & Webster Construction Inc	TE CONNECTIVITY	Cable Splices and Terminations
1057	132176-EY20.01	WSPM003943	Stone & Webster Construction Inc	TE CONNECTIVITY	Cable Splices and Terminations
1058	132175-C913.00	WSPM003265	Stone & Webster Construction Inc	TEAM INDUSTRIES INC	WLS Double Contained Piping
1059	132175F002357	WSPM010610	Stone & Webster Construction Inc	TECHNICAL DIAGNOSTIC SERVICES INC	DOBLE Protective Relaying Test Equipment
1060	132175F002489	WSPM010612	Stone & Webster Construction Inc	TECHNICAL DIAGNOSTIC SERVICES INC	EGIL - Circuit Breaker Analyzer
1061	132175F002539	WSPM010541	Stone & Webster Construction Inc	TECHNICAL DIAGNOSTIC SERVICES INC	HVINC - High Voltage Portable

					HIPOT Tester
1062	132175F002553	WSPM010542	Stone & Webster Construction Inc	TECHNICAL DIAGNOSTIC SERVICES INC	Hipotronics - DC High Potential Tester
1063	132175F003429	WSPM010420	Stone & Webster Construction Inc	TECHNICAL DIAGNOSTIC SERVICES INC	Commissioning - Stroboscope
1064	132175F005719	WSPM004892	WECTEC Global Project Services, Inc.	TELVENT DTN LLC	Web based programs used to monitor and track weather on or around the site (i.e. Phase 1, 2, 3)
1065	WVG3000476	WVG3000476	WECTEC Global Project Services, Inc.	TELVENT DTN LLC	TELVENT WEATHER SENTRY - 876587 3P TRANSFER
1066	132176-E030.01	WSPM003189	Stone & Webster Construction Inc	THE CALVERT CO INC	Vogtle Unit 4 Iso Phase Bus Duct MPA-E030-00 |
1067	132176-E031.01	WSPM010224	Stone & Webster Construction Inc	THE CALVERT CO INC	Vogtle Unit 4 Non Seg Phase Bus Duct MPA-E031-00|
1068	4500657834	4500657834	Westinghouse Electric Company LLC	THE HILLIARD CORP	Lube Oil Mist Eliminator
1069	886652	WSPM004368	WECTEC Global Project Services, Inc.	THOMPSON PUMP AND MFG CO PT	Change Order to Add additional Funds for 2 months on Pump Rental from Thompson Pump PO 886652
1071	132175-C120.00 - REL 1	WSPM004564	Stone & Webster Construction Inc	TIOGA PIPE SUPPLY CO INC	RELEASE 1 BPO B31.1 Pipe and Fittings
1072	132175-C120.00 REL 10	WSPM004565	Stone & Webster Construction Inc	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe and Fittings - Blanket Order
1073	132175-C120.00 REL 11	WSPM010632	Stone & Webster Construction Inc	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe and Fittings - Blanket Order
1074	132175-C120.00 REL 12	WSPM004566	Stone & Webster Construction Inc	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe and Fittings - Blanket Order
1075	132175-C120.00 REL 14	WSPM004567	Stone & Webster Construction Inc	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe and Fittings - Blanket Order
1076	132175-C120.00 REL 15	WSPM010698	Stone & Webster Construction Inc	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe and Fittings - Blanket Order
1077	132175-C120.00 REL 16	WSPM004568	Stone & Webster Construction Inc	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe and Fittings - Blanket Order
1078	132175-C120.00 REL 17	WSPM009968	WECTEC Global Project Services, Inc.	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe and Fittings - Blanket Order
1079	132175-C120.00 REL 18	WSPM009982	WECTEC Global Project Services, Inc.	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe and Fittings - Blanket Order
1080	132175-C120.00 REL 19	WSPM004569	WECTEC Global Project Services, Inc.	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe and Fittings - Blanket Order
1081	132175-C120.00 REL 2	WSPM004570	Stone & Webster Construction Inc	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe and Fittings - Blanket Order

1082	132175-C120.00 REL 20	WSPM004571	WECTEC Global Project Services, Inc.	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe and Fittings - Blanket Order
1083	132175-C120.00 REL 21	WSPM003232	WECTEC Global Project Services, Inc.	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe and Fittings - Blanket Order
1084	132175-C120.00 REL 22	WSPM003233	WECTEC Global Project Services, Inc.	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe and Fittings - Blanket Order
1085	132175-C120.00 REL 23	WSPM003234	WECTEC Global Project Services, Inc.	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe & Fittings Blanket Release
1086	132175-C120.00 REL 24	WSPM010068	WECTEC Global Project Services, Inc.	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe & Fitting Blanket Order Release
1087	132175-C120.00 REL 25	WSPM000582	WECTEC Global Project Services, Inc.	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe & Fitting Blanket Order Release
1088	132175-C120.00 REL 26	WSPM007806	WECTEC Global Project Services, Inc.	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe & Fitting Blanket Order Release
1089	132175-C120.00 REL 7	WSPM004572	Stone & Webster Construction Inc	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe and Fittings - Blanket Order
1090	132175-C120.00 REL 9	WSPM010278	Stone & Webster Construction Inc	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe and Fittings - Blanket Order
1091	132175-C120.00 RELEASE 4	WSPM004573	Stone & Webster Construction Inc	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe and Fittings - Blanket Order
1092	132175-C124.02	WSPM004589	WECTEC Global Project Services, Inc.	TIOGA PIPE SUPPLY CO INC	Alloy Steel Pipe for Condenser C S-83 Replacement
1093	132175-C125.05	WSPM004588	Stone & Webster Construction Inc	TIOGA PIPE SUPPLY CO INC	Stainless Steel Material for the Mechanical Modules and WWS Collection Basin
1094	WSV3B00036	WSV3B00036	WECTEC Global Project Services, Inc.	TIOGA PIPE SUPPLY CO INC	B31.1 Pipe & Fitting Blanket Order Release
1095	132175F002240	WSPM012075	Stone & Webster Construction Inc	TOOLHOUND INC	Barcode Tags for Tools
1096	132175F004501	WSPM015198	Stone & Webster Construction Inc	TOOLHOUND INC	BARCODES FOR CBI OWNED TOOLS
1097	WVG3001305	WVG3001305	WECTEC Global Project Services, Inc.	TOOLHOUND INC	Tool room One Team barcodes
1098	132175F000406	WSPM004649	Stone & Webster Construction Inc	TOTAL STORAGE SERVICES LLC	40 foot connex for storing hydro equipment
1099	132175F000901	WSPM014764	Stone & Webster Construction Inc	TOTAL STORAGE SERVICES LLC	Conex for Facilities General Storage
1100	132175F001108	WSPM004619	Stone & Webster Construction Inc	TOTAL STORAGE SERVICES LLC	Tool Storage
1101	132175F002274	WSPM004426	Stone & Webster Construction Inc	TOTAL STORAGE SERVICES LLC	Storage Conex Annex 3
1102	132175F005686	WSPM004887	WECTEC Global Project Services, Inc.	TOWER 3 GOLF	Management Training-Leadership Alignment Workshop

1103	132175F001320	WSPM010003	Stone & Webster Construction Inc	TPM INC	Staples for Printers
1104	132175-H100.08	WSPM001921	WECTEC Global Project Services, Inc.	TRACHTE LLC	Fire Protection Deluge Valve Houses
1105	132175F003567	WSPM015298	Stone & Webster Construction Inc	TRANSCAT INC	Commissioning - Digital Hydrometer
1106	132175-J500.09	WSPM003748	Stone & Webster Construction Inc	TRENWA INC	Trench System for Security System
1107	132175F005231A	WSPM009960	WECTEC Global Project Services, Inc.	TRI TOOL INC	Equipment to Support Main Steam Piping
1108	J132175-FPR12-01717-00	WSPM002174	Stone & Webster Construction Inc	TRIFAST SYSTEMS INC	Concrete Anchors for RWS Pumphouse Ductbank
1109	132175-J600.03	WSPM003796	Stone & Webster Construction Inc	TRIO FASTENERS INC	Anchor Bolts & Embeds (Area 315 And Make-Up Wells 3 & 4)
1110	132175F004540	WSPM004813	Stone & Webster Construction Inc	TRUCK PARTS SPECIALISTS OF AUGUSTA	Request $25,000 for Truck Parts Specalist of Augusta INC, for parts assoicated with site owned equipment.
1111	4500715821	4500715821	WECTEC Contractors Inc	TRUCK PARTS SPECIALISTS OF AUGUSTA	PARTS
1112	4500715912	4500715912	WECTEC Contractors Inc	TRUCK PARTS SPECIALISTS OF AUGUSTA	PARTS
1113	4500716067	4500716067	WECTEC Contractors Inc	TRUCK PARTS SPECIALISTS OF AUGUSTA	PARTS
1114	4500716528	4500716528	WECTEC Contractors Inc	TRUCK PARTS SPECIALISTS OF AUGUSTA	PARTS
1115	4500716570	4500716570	WECTEC Contractors Inc	TRUCK PARTS SPECIALISTS OF AUGUSTA	PARTS
1116	4500716615	4500716615	WECTEC Contractors Inc	TRUCK PARTS SPECIALISTS OF AUGUSTA	PARTS
1117	4500717463	4500717463	WECTEC Contractors Inc	TRUCK PARTS SPECIALISTS OF AUGUSTA	PARTS

1118	132175F001960	WSPM004442	Stone & Webster Construction Inc	TUCKER SECURITY AND FIRE INC	Add funding to PO 844086 $2000.00
1119	132175F005149	WSPM009955	WECTEC Global Project Services, Inc.	TYFLOT INC	FME Plugs For Use By The Pipefitters Nuclear Island 3.
1120	132175F005191	WSPM009945	WECTEC Global Project Services, Inc.	TYFLOT INC	FME Covers For Pipefitters NI3.
1121	132175F005308	WSPM005014	WECTEC Global Project Services, Inc.	ULINE	TURBINE 3 BARRICADE CONES, CONTACT ERIC PTT 646
1122	132175-EF60.01	WSPM000865	WECTEC Global Project Services, Inc.	UNITED CONTROLS INTERNATIONAL	Local Communication Panels
1123	132176-EF60.01	WSPM001156	WECTEC Global Project Services, Inc.	UNITED CONTROLS INTERNATIONAL	Local Communication Panels
1124	132175F005892	WSPM004712	WECTEC Global Project Services, Inc.	UNIVERSITY OCCUPATIONAL HEALTH CENT	Open PO for Fit for Duty Evaluations - University Occupational
1125	WVG3001031	WVG3001031	WECTEC Global Project Services, Inc.	UPS FREIGHT	Vogtle Freight Shipments-UPS Freight Blanket PO, Brandlow Ludlow
1126	132175-EG01.02	WSPM010459	Stone & Webster Construction Inc	VALLEN	GS Material
1127	132175-EL01.04	WSPM010330	Stone & Webster Construction Inc	VALLEN	Lighting Dimming Control System
1128	132175F000205	WSPM010578	Stone & Webster Construction Inc	VALLEN	Methyl Ethyl Ketone & Methylene Chloride
1129	132175F000863	WSPM005031	Stone & Webster Construction Inc	VALLEN	Sqwincher Sqweeze Pops
1130	132175F000956	WSPM015523	Stone & Webster Construction Inc	VALLEN	To Clean the Turbine Casings
1131	132175F001811	WSPM009734	Stone & Webster Construction Inc	VALLEN	Carboy Stopcock, Rectangular Carboy Stopcock, Total Chlorine Test Kit, & Ph Paper
1132	132175F001982	WSPM009851	Stone & Webster Construction Inc	VALLEN	MSA Filters
1133	132175F001995	WSPM005183	Stone & Webster Construction Inc	VALLEN	Ice Melt
1134	132175F002660	WSPM010055	Stone & Webster Construction Inc	VALLEN	Temporary Construction Aid for Pipefitters in NI-3 for Dewatering in Aux Bldg.
1135	132175F003072	WSPM010102	Stone & Webster Construction Inc	VALLEN	Temporary Construction - Insulators

1136	132175F003283	WSPM010353	Stone & Webster Construction Inc	VALLEN	Non Permant Plant: Construction Aid Material for NI-3 Pipefitters Testing Pipe Dept.
1137	132175F003372	WSPM010361	Stone & Webster Construction Inc	VALLEN	Test Lab- Anti-Seize
1138	132175F004598	WSPM010544	Stone & Webster Construction Inc	VALLEN	SG 2093 HUMIDITY INDICATOR CARDS- Preventive Maintenace Temporary Construction Activities
1139	132175F004870	WSPM009916	Stone & Webster Construction Inc	VALLEN	Batch Plant - pressure reducing valve, wash down nozzle, spray WD40
1140	132175F005042	WSPM009931	WECTEC Global Project Services, Inc.	VALLEN	Gas Detector Tubes
1141	132175F005087	WSPM009972	WECTEC Global Project Services, Inc.	VALLEN	Construction Aid Non Permanent Turbine 3 WP CDS-ME2E-PLW-ME5687
1142	132175F005186	WSPM009956	WECTEC Global Project Services, Inc.	VALLEN	150WATT HALOGEN BULBS FOR BATCH PLANT
1143	132175F005253	WSPM009747	WECTEC Global Project Services, Inc.	VALLEN	Brackets for Eye Wash Stations
1144	132175F005341	WSPM009726	WECTEC Global Project Services, Inc.	VALLEN	3M Particulate Filters P100
1145	132175F005649	WSPM009797	WECTEC Global Project Services, Inc.	VALLEN	Temporary Construction - Plant Maintenance Group
1146	132175F005869	WSPM010134	WECTEC Global Project Services, Inc.	VALLEN	Temporary Construction - Plumbing/Testing - BOP
1147	132175-FPR12-02341-00	WSPM003211	Stone & Webster Construction Inc	VALLEN	Erico Tap & Run Weld Material
1148	132176-E111.02	WSPM003188	Stone & Webster Construction Inc	VALLEN	Turbine Building Elevation 82’-9” and Auxiliary Building Ele
1149	132176-EG01.01	WSPM010296	Stone & Webster Construction Inc	VALLEN	Grounding System Material
1150	132176-EL01.04	WSPM010066	Stone & Webster Construction Inc	VALLEN	Lighting Dimming Control System
1151	J132175-E111.03	WSPM002179	Stone & Webster Construction Inc	VALLEN	Non Class 1 E Ground Cable|
1152	WVG3000058	WVG3000058	WECTEC Global Project Services, Inc.	VALLEN	IH SUPPLIES - HSE FIELD
1153	WVG3000250	WVG3000250	WECTEC Global Project Services, Inc.	VALLEN	Material to be used to support commissioning and testing of instrumentation in buildings like the

					315, 303, Annex, Aux, Turbine, and Containment
1154	WVG3000251	WVG3000251	WECTEC Global Project Services, Inc.	VALLEN	Material to be used to support commissioning and testing of instrumentation in buildings like the 315, 303, Annex, Aux, Turbine, and Containment
1155	WVG3000775	WVG3000775	WECTEC Global Project Services, Inc.	VALLEN	to be used for forms and embeds in the Aux building
1156	WVG3001295	WVG3001295	WECTEC Global Project Services, Inc.	VALLEN	Emergency Respiratory Protection Supplies, Equipment & Services to Support Training for & Rescues with Self-Contained Breathing Apparatus & Supplied Air Breathing Apparatus
1157	132175F002381	WSPM004395	Stone & Webster Construction Inc	VENTYX ENERGY LLC	Ventyx eSOMS Software
1158	132175-Q111.00	WSPM003913	Stone & Webster Construction Inc	VITAL FUEL SYSTMS	Diesel Fuel Tank, Pump, Piping, and Dispenser Station
1159	WVG3001259	WVG3001259	WECTEC Global Project Services, Inc.	VITAL FUEL SYSTMS	Material to be left in place and used for bldg 315 ZRS diesel fuel storage tank Critical LoLo Level Switch, work paclage SV0-ZRS-04-IT001
1160	132175-AD03.01	WSPM003329	Stone & Webster Construction Inc	WALZ AND KRENZER INC	CA20 Watertight Doors
1163	132175F005018	WSPM004825	WECTEC Global Project Services, Inc.	WESTSIDE MEDICAL CENTER	Add Funds to PO 689073 for Westside Medical not to exceed $200,000 or 1 yr.
1164	132175F003228	WSPM013727	Stone & Webster Construction Inc	WHITAKER LABORATORY INC	Batch Plant - Add funds to PO# 689063
1165	132175F003303	WSPM004513	Stone & Webster Construction Inc	WILLIAMS SCOTSMAN INC	CO to PO 633767 extending rental 12 months on 60X24 Mod Box(Williams Scotsman)
1166	132175-C127.02	WSPM009751	WECTEC Global Project Services, Inc.	WOLSELEY INDUSTRIAL GROUP	Copper Tubing and Fittings for Annex PWS Bulk Order
1167	132175F000482	WSPM013403	Stone & Webster Construction Inc	WOLSELEY INDUSTRIAL GROUP	Temporary Piping supplies-Tyrone Davis
1168	132175F004235	WSPM013321	Stone & Webster Construction Inc	WOLSELEY INDUSTRIAL GROUP	Temporary Construction Aid - BOP Plumbing
1169	132175F004309	WSPM004811	Stone & Webster Construction Inc	WOLSELEY INDUSTRIAL GROUP	Temporary Construction Aid - NI4

					Testing
1170	132175F005404	WSPM013315	WECTEC Global Project Services, Inc.	WOLSELEY INDUSTRIAL GROUP	Temporary Construction Aid - BOP - Plumbing/Plant Air
1171	132176F000005	WSPM010694	Stone & Webster Construction Inc	WOLSELEY INDUSTRIAL GROUP	Unit 4 Turbine Building Elevation 82’-9” to Elevation 94’-0” Construction Aid Materials
1172	WVG3000568	WVG3000568	WECTEC Global Project Services, Inc.	WOLVERINE FIRE PROTECTION CO	FIRE PROTECTION DESIGN - 739840 3P TRANS
1173	WVG3000415	WVG3000415	WECTEC Global Project Services, Inc.	WOW BUSINESS SERVICES	TRANSFER OF FUNDS FROM 978644-3P
1174	132175F000542	WSPM010564	Stone & Webster Construction Inc	WW GRAINGER INC	GREEN ACCEPT TAGS
1175	132175F001291	WSPM013387	Stone & Webster Construction Inc	WW GRAINGER INC	GREEN ACCEPT TAGS/RED HOLD TAGS/RED RISK RELEASE TAGS
1176	132175F003073	WSPM011188	Stone & Webster Construction Inc	WW GRAINGER INC	Commissioning - FLIR Infrared Imagers
1177	132175F004590	WSPM010543	Stone & Webster Construction Inc	WW GRAINGER INC	Desiccant material for Preventive Maintence Temporary Construction activities-SG 1908 for 16 unit and no SDS required for the 2 unit desiccant
1178	132175F005086	WSPM009971	WECTEC Global Project Services, Inc.	WW GRAINGER INC	Humidty Control in Level A Storage
1179	132175F005244	WSPM009722	WECTEC Global Project Services, Inc.	WW GRAINGER INC	PM Water Quality Lab Supplies Pipette tips 100 to1000 microlite P/N 21R685 and stir bars
1180	132175F005356	WSPM009723	WECTEC Global Project Services, Inc.	WW GRAINGER INC	Drager Tubes
1181	132175F005566	WSPM004894	WECTEC Global Project Services, Inc.	WW GRAINGER INC	Magnifying glasses for Labeling team to read drawings and tags for the Perm plant Temporary const. equipment labeling
1182	132175F005781	WSPM010126	WECTEC Global Project Services, Inc.	WW GRAINGER INC	Confined Space Modules Work
1183	WVG3000078	WVG3000078	WECTEC Global Project Services, Inc.	WW GRAINGER INC	Turbidity Meter for Water Quality Lab activities,
1184	WVG3000202	WVG3000202	WECTEC Global Project Services, Inc.	WW GRAINGER INC	PM Temporary Construction Activities, Wood Screws for Wboro Warehouse to build crates and dunnage

1185	WVG3000265	WVG3000265	WECTEC Global Project Services, Inc.	WW GRAINGER INC	MAB Emergency Notification Tool
1186	WVG3000287	WVG3000287	WECTEC Global Project Services, Inc.	WW GRAINGER INC	Bondo for Formwork Repair in Precast Yard
1187	WVG3000955	WVG3000955	WECTEC Global Project Services, Inc.	WW GRAINGER INC	Temp Const. Activities Consumable
1188	WVG3000985	WVG3000985	WECTEC Global Project Services, Inc.	WW GRAINGER INC	To be used for rebar fabrication shops in NOI-6/7/8/9/10
1189	132175F005158-REL-001	WSPM009959	WECTEC Global Project Services, Inc.	YAK MAT LLC	RELEASE 001 YAK Mat LLC, POC: Chad West 912-551-2207. For crane mats.
1190	132175F005158-REL-002	WSPM009801	WECTEC Global Project Services, Inc.	YAK MAT LLC	BLANKET RELEASE FOR CRANE MATS
1191	WVG3001529	WVG3001529	WECTEC Global Project Services, Inc.	YAK MAT LLC	Timber crane mats to be used as a load spreading footing for new Liebherr LR-11350 crawler crane
1192	132175F000763	WSPM015065	Stone & Webster Construction Inc	YANCEY BROTHERS CO	BRADCO TRENCHER CHAIN AND TEETH SPARE
1193	132175F001532	WSPM009941	Stone & Webster Construction Inc	YANCEY BROTHERS CO	YANCEY TO R AND R FORKLIFT TIRE ON TH514
1194	132175F002565	WSPM004503	Stone & Webster Construction Inc	YANCEY BROTHERS CO	TH514 SER# 0TBW00765 Yancey To Repair Tilt Cylinder Damage
1195	132175F002931	WSPM004394	Stone & Webster Construction Inc	YANCEY BROTHERS CO	SERVICES FOR DGU INSTALLATION
1196	132175F003772	WSPM004490	Stone & Webster Construction Inc	YANCEY BROTHERS CO	Request $355.07 to replace missing Hitch pins from TH-514 forklifts.
1197	132175F004219	WSPM004872	Stone & Webster Construction Inc	YANCEY BROTHERS CO	Request $172.31 for repair of Yancey TH-514 Ser# 0MWC00267 ignition switch caused by site danmage. See attached invoice.
1198	132175F004539	WSPM004814	Stone & Webster Construction Inc	YANCEY BROTHERS CO	Request $25,000 for service and parts assoicated with site damaged rental equipment from YANCEY.
1199	WVG3000906	WVG3000906	Stone & Webster Construction Inc	YANCEY BROTHERS CO	Repair Carriage/Coupler Assemby and Windshield - Forklift totaling $17,080.00
1200	132175-D100.17	WSPM014779	Stone & Webster Construction Inc	YEAROUT INDUSTRIAL LLC	CA03 Module Material
1201	132175-K105.01	WSPM014776	Stone & Webster Construction Inc	YOKOGAWA CORP OF AMERICA	FLOW PITOT TUBE W/INTEGRAL TRANSMITTER

1202	132175-MY51.00	WSPM003926	WECTEC Global Project Services, Inc.	CHROMALOX INC	MY51 Electric Heaters
1203	132176-MY51.00	WSPM003043	WECTEC Global Project Services, Inc.	CHROMALOX INC	MY51 Electric Heaters
1204	132176-C202.15	132176-C202.15	WECTEC Global Project Services, Inc.	Lanier Municipal Supply Co Inc	Post Indicator Valves for FPS
1205	4500446434	4500446434	Westinghouse Electric Company LLC	COMPOSITE COOLING SOLUTIONS	Induced Draft Cooling Tower Package
1207	132176-EW31.01	132176-EW31.01	WECTEC Global Project Services, Inc.	CABLELAN NUCLEAR	FIBER OPTIC CABLE
1208	132175-EW31.01	132175-EW31.01	WECTEC Global Project Services, Inc.	CABLELAN NUCLEAR	Fiber Optic Cable
1209	132175-J800.26	132175-J800.26	WECTEC Global Project Services, Inc.	APPLIED TECHNICAL SERVICES INC	
1210	132175-MY51.01	132175-MY51.01	WECTEC Global Project Services, Inc.	Indeeco	Unit Heaters
1211	132176-MY51.01	132176-MY51.01	WECTEC Global Project Services, Inc.	Indeeco	Unit Heaters
1212	132175F000097	132175F000097	WECTEC Global Project Services, Inc.	Landrum Supply Co	Ice House Drinking Water System
1213	132175F000302	N/A	WECTEC Global Project Services, Inc.	New PIG	FOR DONNY JOHNSON-WAREHOUSE STORAGE
1214	132175F005955A	WSPM015196	WECTEC Global Project Services, Inc.	Toolhound Inc.	Barcodes for Tools and Scanner

B. Service Provider shall assume the subcontracts and purchase orders listed below but will not assign the subcontracts and purchase orders to Owners. Instead, Service Provider will amend the subcontracts and purchase orders listed below to include Owners or their designee as an additional party with all rights, claims, and defenses as are possessed by Service Provider under the terms of the subcontract or purchase order.

	Purchase Order/ Subcontract	SAP PO	Debtor	SubContractor/Vendor	Contract Description/Title
1	4500645097	4500645097	Westinghouse Electric Company LLC	3SPACE INC	2411401 Vogtle Tank Measurement Support
2	4500408960	4500408960	Westinghouse Electric Company LLC	ABB INC	Main Generator Circuit Breaker
3	4500458067	4500458067	Westinghouse Electric Company LLC	ABB INC	Neutral Grounding Transformer

4	132175-G230.04	WSPM003206	WECTEC Global Project Services, Inc.	AECON INDUSTRIAL	ASME III Mechanical Modules
5	132176-G230.04	WSPM003940	WECTEC Global Project Services, Inc.	AECON INDUSTRIAL	ASME III Mechanical Modules
6	4500379569	4500379569	Westinghouse Electric Company LLC	ALFA LAVAL	SFS Heat Exchangers
7	4500693387	4500693387	Westinghouse Electric Company LLC	ALLIED RUBBER AND SUPPLY	Mechanical Connections/Quick Disconnects
8	4500371102	4500371102	Westinghouse Electric Company LLC	AMER INDUSTRIAL TECHNOLOGIES, INC.	Fuel Transfer Tube
9	4500385789	4500385789	Westinghouse Electric Company LLC	AMER INDUSTRIAL TECHNOLOGIES, INC.	VES Air Tank Package
10	4500666213	4500666213	Westinghouse Electric Company LLC	AMERICAN TANK & VESSEL INC	PCS Passive Containment Cooling Ancillary Water Storage Tank
11	4500666219	4500666219	Westinghouse Electric Company LLC	AMERICAN TANK & VESSEL INC	CVS Boric Acid Tank
12	132175-C651.04	WSPM010358	Stone & Webster Construction Inc	ANVIL INTERNATIONAL INC	YFS And RWS Pipe Support Material
13	132175-C651.07	WSPM009746	WECTEC Global Project Services, Inc.	ANVIL INTERNATIONAL INC	Non-Safety Related Pipe Support Material
14	132175-PH03.01A	WSPM004557	WECTEC Global Project Services, Inc.	ANVIL INTERNATIONAL INC	Shop Fabricated ASME B31.1 Supports - PH03.01A
15	132176-PH03.01A	WSPM004737	WECTEC Global Project Services, Inc.	ANVIL INTERNATIONAL INC	Shop Fabricated ASME B31.1 Supports - PH03.01A
16	4500636703	4500636703	Westinghouse Electric Company LLC	ARINC INC	Delivery to Site - SV3
17	4500440120	4500440120	Westinghouse Electric Company LLC	ASTRO AUTOMATION INC	New RCC Handling Tool
18	4500629276	4500629276	Westinghouse Electric Company LLC	ASTRO AUTOMATION INC	Reactor Coolant Pump/Motor Maintenance Cart
19	4500633087	4500633087	Westinghouse Electric Company LLC	ASTRO AUTOMATION INC	Reactor Coolant Pump/Motor Maintenance Cart
20	4500696026	4500696026	Westinghouse Electric Company LLC	ASTRO AUTOMATION INC	RCP Casing Stand Storage Disassembly
21	4500336213	4500336213	Westinghouse Electric Company LLC	AT&F ADVANCED METALS	WLS Vapor Condenser
22	4500336026	4500336026	Westinghouse Electric Company LLC	AT&F NUCLEAR	SV4 Waste Holdup & Mon Tank MT3L
23	4500665080	4500665080	Westinghouse Electric Company LLC	AT&F NUCLEAR	PXS ph Adjustment Baskets

25	4500649171	4500649171	Westinghouse Electric Company LLC	AT&F NUCLEAR	Stilling Well
26	132175-MS05.00	WSPM003991	WECTEC Global Project Services, Inc.	ATLAS COPCO COMPRESSORS LLC	Air Compressor, Air Dryer and Receiver Packages for Instrument Air and Services Subsystems
27	132176-MS05.00	WSPM003388	WECTEC Global Project Services, Inc.	ATLAS COPCO COMPRESSORS LLC	Air Compressor, Air Dryer and Receiver Packages for Instrument Air and Services Subsystems
28	4500387738	4500387738	Westinghouse Electric Company LLC	ATLAS INDUSTRIAL MFG CO	RNS Normal RHR Heat Exchangers
29	4500371040	4500371040	Westinghouse Electric Company LLC	ATLAS INDUSTRIAL MFG CO	SV3 Heat Exchanger, CVS Letdown, ME2S
30	4500433682	4500433682	Westinghouse Electric Company LLC	ATLAS INDUSTRIAL MFG CO	Containment Piping Penetrations with Flued Heads
31	4500687086	4500687086	Westinghouse Electric Company LLC	ATLAS INDUSTRIAL MFG CO	High Pressure Cartridge Filters (Reactor Coolant Filters)
32	4500644157	4500644157	Westinghouse Electric Company LLC	ATLAS INDUSTRIAL MFG CO	MV60 Seismic Repair- Return to Storage
33	4500654412	4500654412	Westinghouse Electric Company LLC	ATLAS INDUSTRIAL MFG CO	Authorized Inspection charge at site
34	4500656014	4500656014	Westinghouse Electric Company LLC	ATLAS INDUSTRIAL MFG CO	Degasifier Column, Vertical (re-rated)
35	4400127848	4400127848	Westinghouse Electric Company LLC	BENTLEY WORLD PACKAGING LTD	Pressure Heater Controller for SV3.
36	4400131010	4400131010	Westinghouse Electric Company LLC	BENTLEY WORLD PACKAGING LTD	VOGTLE 3 MCR/RSR TRANSFER PANEL
37	4400131012	4400131012	Westinghouse Electric Company LLC	BENTLEY WORLD PACKAGING LTD	VOGTLE 4 MCR/RSR TRANSFER PANEL
38	4400131013	4400131013	Westinghouse Electric Company LLC	BENTLEY WORLD PACKAGING LTD	VOGTLE 3 OCS PRINTER STANDS
39	4400131014	4400131014	Westinghouse Electric Company LLC	BENTLEY WORLD PACKAGING LTD	VOGTLE 3 WALL PANEL INFORMATION SYSTEM
40	4400133271	4400133271	Westinghouse Electric Company LLC	BENTLEY WORLD PACKAGING LTD	INVOICE 480-JI-00742
41	4400133649	4400133649	Westinghouse Electric Company LLC	BENTLEY WORLD PACKAGING LTD	SV4 PHC & Spares
42	4400134340	4400134340	Westinghouse Electric Company LLC	BENTLEY WORLD PACKAGING LTD	Vogtle - Packaging, Container Loading
43	4400136330	4400136330	Westinghouse Electric Company LLC	BENTLEY WORLD PACKAGING LTD	SV4 OCS Printer Stands
44	4400136331	4400136331	Westinghouse Electric Company LLC	BENTLEY WORLD PACKAGING LTD	VS3 OCS Printer Stands

45	4400138050	4400138050	Westinghouse Electric Company LLC	BENTLEY WORLD PACKAGING LTD	AP1000 DRPI System and Install kits Vogt
46	4400152032	4400152032	Westinghouse Electric Company LLC	BENTLEY WORLD PACKAGING LTD	Vogtle Unit 3 PLS Batch 1 FCN Parts
47	4400152556	4400152556	Westinghouse Electric Company LLC	BENTLEY WORLD PACKAGING LTD	AP1000 PMS VOGTLE UNIT 4
48	4500414207	4500414207	Westinghouse Electric Company LLC	BEST LINE EQUIPMENT	Auxiliary Building Inspection Platform
49	4500379105	4500379105	Westinghouse Electric Company LLC	BHI, INC	Containment Piping Penetrations with Flued Heads
54	4500673868	4500673868	Westinghouse Electric Company LLC	CAMERON MEASUREMENT SYSTEMS PA	AP1000 JE25 Ultrasonic Flowmeters
55	4500368833	4500368833	Westinghouse Electric Company LLC	CAMERON MEASUREMENT SYSTEMS PA	Feedwater Ultrasonic Flow Measurement Package
56	132175-MS11.00	WSPM003867	WECTEC Global Project Services, Inc.	CAMFIL	Air Filtration Units
57	132176-MS11.00	WSPM003048	WECTEC Global Project Services, Inc.	CAMFIL	Air Filtration Units
58	132175-CR01.03	WSPM003257	WECTEC Global Project Services, Inc.	CAROLINA FABRICATORS INC	Welded Hoop Ties at Wall 11
59	132175-D500.49	WSPM007807	WECTEC Global Project Services, Inc.	CAROLINA FABRICATORS INC	Steel Grating For 300 Series Transformers
60	132175-SS01.47	WSPM010615	WECTEC Global Project Services, Inc.	CAROLINA FABRICATORS INC	Personnel Hatch Penetration Seal Rings
61	132176-CR01.03	WSPM003751	WECTEC Global Project Services, Inc.	CAROLINA FABRICATORS INC	Welded Hoop Ties at Wall 11
62	132176-SS01.47	WSPM010852	WECTEC Global Project Services, Inc.	CAROLINA FABRICATORS INC	Personnel Hatch Penetration Seal Rings
63	132175-C121.01-00	WSPM004574	WECTEC Global Project Services, Inc.	CB&I LAURENS INC	Carbon Steel Pipe
64	132175-C601.01	WSPM004587	WECTEC Global Project Services, Inc.	CB&I LAURENS INC	Shop Fabricated ASME B31.1 Piping
65	132175-C601.03	WSPM004529	WECTEC Global Project Services, Inc.	CB&I LAURENS INC	Equipment Module Piping
66	132175-C601.04	WSPM010233	Stone & Webster Construction Inc	CB&I LAURENS INC	Fabrication of R365 Module
67	132175-C601.08	WSPM004530	WECTEC Global Project Services, Inc.	CB&I LAURENS INC	Shop Fabricated Piping for ASME III Modules

68	132175-C607.01-00	WSPM004598	WECTEC Global Project Services, Inc.	CB&I LAURENS INC	Pipe Spools|
69	132175-C607.02	WSPM004597	WECTEC Global Project Services, Inc.	CB&I LAURENS INC	Pipe Sleeves|
70	132176-C601.01	WSPM004908	WECTEC Global Project Services, Inc.	CB&I LAURENS INC	Shop Fabricated ASME B31.1 Piping
71	132176-C601.03	WSPM004909	WECTEC Global Project Services, Inc.	CB&I LAURENS INC	Equipment Module Piping
72	132176-C601.04	WSPM003764	WECTEC Global Project Services, Inc.	CB&I LAURENS INC	Fabrication of R365 Module
73	132176-C601.08	WSPM004910	WECTEC Global Project Services, Inc.	CB&I LAURENS INC	Shop Fabricated ASME III Piping for ASME III Mechanical Modules
74	132176-C607.01-00	WSPM010144	Stone & Webster Construction Inc	CB&I LAURENS INC	Pipe Spools|
75	132176-C607.02	WSPM004911	WECTEC Global Project Services, Inc.	CB&I LAURENS INC	Pipe Sleeves|
76	J132175-C121.02	WSPM002188	WECTEC Global Project Services, Inc.	CB&I LAURENS INC	Steel Pipe, Fittings|
77	J132175-C125.01-00	WSPM002187	WECTEC Global Project Services, Inc.	CB&I LAURENS INC	SS Pipe|
78	J132175-C601.02	WSPM004370	WECTEC Global Project Services, Inc.	CB&I LAURENS INC	Shop Fabricated ASME III Piping|
79	J132176-C121.01	WSPM010143	Stone & Webster Construction Inc	CB&I LAURENS INC	Carbon Steel Pipe
80	J132176-C601.02	WSPM004376	WECTEC Global Project Services, Inc.	CB&I LAURENS INC	Shop Fabricated ASME III Piping|
81	WVG3000605	WVG3000605	WECTEC Global Project Services, Inc.	CB&I LAURENS INC	DELIVERY MILESTONES - 972280 OP TRANS
82	4500328462	4500328462	Westinghouse Electric Company LLC	CCI AG	IRWST and Containment Recirculation Screens
83	4500425679	4500425679	Westinghouse Electric Company LLC	CCI AG	Main Steam Power Operated Relief Valves (MSPORV)
85	4500412721	4500412721	Westinghouse Electric Company LLC	CCI AG	Feedwater Control Valves (FCV)
86	4500662064	4500662064	Westinghouse Electric Company LLC	CHALMERS & KUBECK INC	Steam Generators
87	4500625876	4500625876	Westinghouse Electric Company LLC	CHERRY ENGINEERING INC	Engineering Services
88	4500340787	4500340787	Westinghouse Electric Company LLC	CHROMALOX, INC.	Recirculation Heaters - PCS
89	132175-CE01.01	WSPM003262	WECTEC Global Project Services, Inc.	CIVES STEEL CO	EMBEDS - Aux Bldg 66’6” to 82’6” (A2-CS-X, CE01, SV3)

CONFIDENTIAL& PROPRIETARY
CONFIDENTIAL TRADE SECRET INFORMATION

90	132175-D100.16 RELEASE 1	WSPM003450	WECTEC Global Project Services, Inc.	CIVES STEEL CO	Fabrication & Commodities for Vogtle Units 3 & 4
91	132175-D100.16 RELEASE 2	WSPM003449	WECTEC Global Project Services, Inc.	CIVES STEEL CO	Fabrication & Commodities for Vogtle Units 3 & 4
92	132175-D500.12	WSPM003377	WECTEC Global Project Services, Inc.	CIVES STEEL CO	Leak Chase Material
93	132176-CE01.01	WSPM003757	WECTEC Global Project Services, Inc.	CIVES STEEL CO	Safety Related Embeds/Anchors (A1, A2, A3, A4, A5, A6, AA1, C2, C3, C4-CS-X) CE01
94	4500460933	4500460933	Westinghouse Electric Company LLC	CLARK COOPER DIVISION OF MAGNATROL	Solenoid Operated Globe Valves (B16.34 Exclusion)
95	132175-CE01.04-REL 1	WSPM007198	WECTEC Global Project Services, Inc.	CONSOLIDATED PIPE AND SUPPLY CO INC	Safety-Related Embed Plates and Miscellaneous Steel
96	132175-CE01.04-REL 2	WSPM007197	WECTEC Global Project Services, Inc.	CONSOLIDATED PIPE AND SUPPLY CO INC	Safety-Related Embed Plates and Miscellaneous Steel
97	132175-MY04.01	WSPM003928	WECTEC Global Project Services, Inc.	CONSOLIDATED PIPE AND SUPPLY CO INC	VFS Debris Screen, ASME Section III, Class 3
98	132176-CE01.04-REL 1	WSPM007219	WECTEC Global Project Services, Inc.	CONSOLIDATED PIPE AND SUPPLY CO INC	Safety-Related Embed Plates and Miscellaneous Steel
99	132176-CE01.04-REL 2	WSPM007218	WECTEC Global Project Services, Inc.	CONSOLIDATED PIPE AND SUPPLY CO INC	Safety-Related Embed Plates and Miscellaneous Steel
100	132176-MY04.01	WSPM003045	WECTEC Global Project Services, Inc.	CONSOLIDATED PIPE AND SUPPLY CO INC	VFS Debris Screen, ASME Section III, Class 3
101	4500642121	4500642121	Westinghouse Electric Company LLC	CONSOLIDATED POWER SUPPLY	Bar,Alloy 690,14.5” Dia,ASME III-NB
102	132175-CE01.04-REL 3	WSPM011054	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	Safety-Related Embed Plates and Miscellaneous Steel
103	132175-CR01.06	WSPM003256	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	Safety Related Mechanical Splices for Reinforcing Steel, Conforming to APP-CR01-Z0-010
104	132175-D100.07	WSPM004534	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	Pipe Support Shim Material
105	132175-PL02.03 REL 1	WSPM013516	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	ASME III Piping Materials Blanket
106	132175-PL02.08	WSPM010897	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	Fabrication of ASME III Piping Spools
107	132176-CE01.04-REL 3	WSPM011055	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	Safety-Related Embed Plates and Miscellaneous Steel
108	132176-PL02.08	WSPM010895	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	Fabrication of ASME III Piping

					Spools
109	132175-CE01.04-REL 4	WSPM015721	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	Safety-Related Embed Plates and Miscellaneous Steel
110	132176-CE01.04-REL 4	WSPM015722	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	Safety-Related Embed Plates and Miscellaneous Steel
111	132176-CR01.06	WSPM003740	WECTEC Global Project Services, Inc.	CONSOLIDATED POWER SUPPLY	Safety Related Mechanical Splices for Reinforcing Steel, Conforming to APP-CR01-Z0-010
112	4500315746	4500315746	Westinghouse Electric Company LLC	CONTROL COMPONENTS INC.	Pressure Regulating Globe Valves, ASME B16.34
113	4500312904	4500312904	Westinghouse Electric Company LLC	CRANE NUCLEAR INC	Ball and Plug Valves, ASME Boiler and Pressure Vessel Code Section III Class 2 and 3
114	4500365224	4500365224	Westinghouse Electric Company LLC	CRANE NUCLEAR INC	Motor Operated Gate and Globe Valves, ASME B16.34
116	4500608832	4500608832	Westinghouse Electric Company LLC	CRANE NUCLEAR INC	3” & Larger Manually Operated Gate, Globe, & Check Vlvs, ASME B16.34
117	4500414861	4500414861	Westinghouse Electric Company LLC	CRANE NUCLEAR INC	Ball and Plug Valves, ASME B16.34
118	4500322834	4500322834	Westinghouse Electric Company LLC	CRANE NUCLEAR INC	Three-Way ASME B16.34 Valves
119	4500265132	4500265132	Westinghouse Electric Company LLC	CURTISS WRIGHT EMCORP	RCS Reactor Coolant Pumps - ASME Section III
120	4500700854	4500700854	Westinghouse Electric Company LLC	CURTISS-WRIGHT FLOW CTRL QUALTECH	Tank,Collection,CCS,Relief Vlv Discharge
121	4500700859	4500700859	Westinghouse Electric Company LLC	CURTISS-WRIGHT FLOW CTRL QUALTECH	Tank,Collection,CCS,Relief Vlv Discharge
123	4500700868	4500700868	Westinghouse Electric Company LLC	CURTISS-WRIGHT FLOW CTRL QUALTECH	Containment Flood-up Weirs
124	4500710537	4500710537	Westinghouse Electric Company LLC	CURTISS-WRIGHT FLOW CTRL QUALTECH	Aux Bldg Expansion Gap Radiation Shield
125	4500325875	4500325875	Westinghouse Electric Company LLC	CURTISS-WRIGHT NUCLEAR DIVISION	SFS Spent Fuel System Cooling Pumps
126	4500611385	4500611385	Westinghouse Electric Company LLC	CURTISS-WRIGHT NUCLEAR DIVISION	SV3- MP2U BAST Recirc Pump
127	4500330217	4500330217	Westinghouse Electric Company LLC	CURTISS-WRIGHT NUCLEAR DIVISION	WLS Reactor Coolant Drain Tank Pumps
128	4500336294	4500336294	Westinghouse Electric Company LLC	CURTISS-WRIGHT NUCLEAR DIVISION	WLS Degasifier Separator Pumps
129	4500656834	4500656834	Westinghouse Electric	CURTISS-WRIGHT	1” & 2” Manually Operated Globe

			Company LLC	NUCLEAR DIVISION	and Check Valves, ASME Sec III Cl 1, 2, & 3
130	4500328840	4500328840	Westinghouse Electric Company LLC	CURTISS-WRIGHT NUCLEAR DIVISION	3" & Larger Man Operated Gate, Globe and Check Vlvs, ASME Sec III Cl 1,2,3
131	4500695579	4500695579	Westinghouse Electric Company LLC	CURTISS-WRIGHT NUCLEAR DIVISION	1" & 2" Manually Operated Globe and Check Valves, ASME B16.34
132	4500695586	4500695586	Westinghouse Electric Company LLC	CURTISS-WRIGHT NUCLEAR DIVISION	1" & 2" Manually Operated Globe and Check Valves, ASME B16.34
134	4500703315	4500703315	Westinghouse Electric Company LLC	DIETERICH STANDARD INC	JE79 Load Change Evaluation
135	4500264977	4500264977	Westinghouse Electric Company LLC	DOOSAN HEAVY INDUSTRIES &	Steam Generators
136	4500264953	4500264953	Westinghouse Electric Company LLC	DOOSAN HEAVY INDUSTRIES &	Reactor Vessel Equipment
137	4500365096	4500365096	Westinghouse Electric Company LLC	DRESSER CONSOLIDATED	Main Steam Safety Valves (MSSV)
138	4500658075	4500658075	Westinghouse Electric Company LLC	DRS CONSOLIDATED CONTROLS INC	Switch,Transfer,3-Phase,4-Pole,208/120 V
139	4500426690	4500426690	Westinghouse Electric Company LLC	DRS CONSOLIDATED CONTROLS INC	Vogtle 3 Preamplifiers (8)
140	132175-D100.CA004	WSPM003448	WECTEC Global Project Services, Inc.	DUBOSE NATIONAL ENERGY SERVICES INC	Select CH & CS Module Fabrication
141	132175-JT01.01	WSPM011809	Stone & Webster Construction Inc	DUBOSE NATIONAL ENERGY SERVICES INC	ASME III Tubing
142	132175-SH22.02	WSPM003912	WECTEC Global Project Services, Inc.	DUBOSE NATIONAL ENERGY SERVICES INC	ELECTRICAL CONDUIT AND JUNCTION BOX SUPPORTS
143	132175-SH25.01	WSPM003911	WECTEC Global Project Services, Inc.	DUBOSE NATIONAL ENERGY SERVICES INC	Seismic Category I Cable Tray Supports
144	132175-SH25.02	WSPM009833	Stone & Webster Construction Inc	DUBOSE NATIONAL ENERGY SERVICES INC	Seismic Category I Cable Tray Supports
145	132176-D100.CA004	WSPM003739	WECTEC Global Project Services, Inc.	DUBOSE NATIONAL ENERGY SERVICES INC	Select CH & CS Module Fabrication
146	132176-SH22.02	WSPM003140	WECTEC Global Project Services, Inc.	DUBOSE NATIONAL ENERGY SERVICES INC	Electrical Conduit and Junction Box Supports
147	132176-SH25.01	WSPM003139	WECTEC Global Project Services, Inc.	DUBOSE NATIONAL ENERGY SERVICES INC	Cat I Cable Tray Supports
148	132176-SH25.02	WSPM009834	Stone & Webster Construction Inc	DUBOSE NATIONAL ENERGY SERVICES INC	Seismic Category I Cable Tray Supports
149	4500666297	4500666297	Westinghouse Electric Company LLC	E.S. FOX LIMITED	CHANGE NOTICE ITEMS WITH QUALITY

150	4500666464	4500666464	Westinghouse Electric Company LLC	E.S. FOX LIMITED	Immersion Heater
151	4500644922	4500644922	Westinghouse Electric Company LLC	EAGLE EYE POWER SOLUTIONS LLC	Automatic Battery Monitors
152	4500691866	4500691866	Westinghouse Electric Company LLC	EAGLE EYE POWER SOLUTIONS LLC	Automatic Battery Monitors
153	4500678038	4500678038	Westinghouse Electric Company LLC	EATON CORP	Non-Class 1E Fused Transfer Switch Boxes
154	4500678040	4500678040	Westinghouse Electric Company LLC	EATON CORP	AC Distribution Panels
155	4500674897	4500674897	Westinghouse Electric Company LLC	EATON CORP	Non-1E Dry Type Transformers for Power and Lighting
156	132175-DF02.01	WSPM001413	WECTEC Global Project Services, Inc.	EATON CORP	Non 1E Fused Transfer Switch Boxes
157	132175-DS02.01	WSPM009993	Stone & Webster Construction Inc	EATON CORP	Non 1E 250 VDC Switchboards
158	132175-E028.02	WSPM003362	WECTEC Global Project Services, Inc.	EATON CORP	Non-Class 1E Dry-Type Transformers
159	132175-E028.03	WSPM003361	WECTEC Global Project Services, Inc.	EATON CORP	Non-Class 1E Liquid Immersed Transformers for Step-Up Operation
160	132175-EA02.01	WSPM002955	WECTEC Global Project Services, Inc.	EATON CORP	Non-Class 1E AC Distribution Panels for EDS
161	132175-EB02.02	WSPM002953	WECTEC Global Project Services, Inc.	EATON CORP	Non-Segregated Phase Bus Duct for Electric Auxiliary Boiler
162	132175-EC01.01	WSPM002952	WECTEC Global Project Services, Inc.	EATON CORP	Motor Control Centers
163	132175-ED01.01	WSPM002949	WECTEC Global Project Services, Inc.	EATON CORP	480Y/277 VAC and 208Y/120 VAC Distribution Panels
164	132175-EK01.01	WSPM010306	Stone & Webster Construction Inc	EATON CORP	Non-Class 1E Low Voltage Load Centers and Bus Duct
165	132175-ES01.01	WSPM002961	WECTEC Global Project Services, Inc.	EATON CORP	Medium Voltage Switchgear
166	132175-ET30.01	WSPM010299	Stone & Webster Construction Inc	EATON CORP	General Purpose Dry Type Transformer
167	132175-EY11.01	WSPM003153	WECTEC Global Project Services, Inc.	EATON CORP	Non-Class 1E Disconnect Switches
168	132176-DF02.01	WSPM001169	WECTEC Global Project Services, Inc.	EATON CORP	Non-Class 1E Fused Transfer Switch Boxes
169	132176-DS02.01	WSPM003190	WECTEC Global Project Services, Inc.	EATON CORP	Non 1E 250 VDC Switchboards

170	132176-EA02.01	WSPM003186	WECTEC Global Project Services, Inc.	EATON CORP	Non-Class 1E AC Distribution Panels for EDS
171	132176-EB02.02	WSPM003116	WECTEC Global Project Services, Inc.	EATON CORP	Non-Segregated Phase Bus Duct for Electric Auxiliary Boiler
172	132176-ED01.01	WSPM003114	WECTEC Global Project Services, Inc.	EATON CORP	480Y/277 VAC and 208Y/120 VAC Distribution Panels
173	132176-ET30.01	WSPM010269	Stone & Webster Construction Inc	EATON CORP	General Purpose Dry Type Transformer
174	132176-EY11.01	WSPM003944	WECTEC Global Project Services, Inc.	EATON CORP	Non-Class 1E Disconnect Switches
175	J132175-E051.01-00	WSPM002181	WECTEC Global Project Services, Inc.	EATON CORP	Non Class 1E Low Voltage Secondary Unit Substations
176	J132175-E052.01-00	WSPM002180	WECTEC Global Project Services, Inc.	EATON CORP	Non-Class 1E 480 V Motor Control Centers|
177	132176-EC01.01	WSPM003115	WECTEC Global Project Services, Inc.	EATON CORP	Motor Control Centers
178	132176-EK01.01	WSPM003110	WECTEC Global Project Services, Inc.	EATON CORP	Non-Class 1E Low Voltage Load Centers and Bus Duct
179	132176-ES01.01	WSPM003955	WECTEC Global Project Services, Inc.	EATON CORP	Medium Voltage Switchgear
180	4500406021	4500406021	Westinghouse Electric Company LLC	EBARA CORPORATION	SWS Service Water Pumps (Vertical Wetpit)
181	4500372318	4500372318	Westinghouse Electric Company LLC	EBARA CORPORATION	FWS Startup Feedwater Pumps (Horizontal Multi-Stage Centrifugal)
182	4500406266	4500406266	Westinghouse Electric Company LLC	EBARA CORPORATION	CCS Component Cooling Water Pumps
184	4500402050	4500402050	Westinghouse Electric Company LLC	EFACEC USA INC	Three-Winding Unit Auxiliary Transformers
185	4500629261	4500629261	Westinghouse Electric Company LLC	ELLIS & WATTS GLOBAL INDUSTRIES INC	Safety Related Ductwork and Expansion Joints
186	4500682178	4500682178	Westinghouse Electric Company LLC	ELLIS & WATTS GLOBAL INDUSTRIES INC	PSS Delay Coils
187	4500630741	4500630741	Westinghouse Electric Company LLC	ELLIS & WATTS GLOBAL INDUSTRIES INC	IRWST Vent and Overflow Weir Covers
189	132175-MS10.00	WSPM001587	WECTEC Global Project Services, Inc.	ELLIS & WATTS GLOBAL INDUSTRIES INC	MS10 Air Handling Units
190	132175-MS14.00	WSPM010393	Stone & Webster Construction Inc	ELLIS & WATTS GLOBAL INDUSTRIES INC	MS14 - Containment Recirculation Fan Coil Units
191	4500628794	4500628794	Westinghouse Electric Company LLC	EMERSON PROCESS MANAGEMENT	Engineer (Days)
192	4500702350	4500702350	Westinghouse Electric	EMERSON PROCESS	ALL SV3 BATCH 1A DDS PARTS

			Company LLC	MANAGEMENT	
193	4500702389	4500702389	Westinghouse Electric Company LLC	EMERSON PROCESS MANAGEMENT	ALL SV4 BATCH 1A DDS PARTS
194	132175-PH02.04	WSPM003922	WECTEC Global Project Services, Inc.	ENERGY AND PROCESS CORP	ASME III Subsection NF Support Materials
195	132175-PL02.02	WSPM004558	WECTEC Global Project Services, Inc.	ENERGY AND PROCESS CORP	ASME III Cat. I/B Piping Materials for SFS System, Module CA01
196	4500416495	4500416495	Westinghouse Electric Company LLC	ENERGY STEEL AND SUPPLY CO	Reactor Coolant System Support Components Includes: RV, SG, PZR
197	4500427657	4500427657	Westinghouse Electric Company LLC	ENERGY STEEL AND SUPPLY CO	Reactor Coolant System Support Components Includes: RV, SG, PZR
199	132175-C607.04	WSPM015711	WECTEC Global Project Services, Inc.	ENERGY STEEL AND SUPPLY CO	Fabrication of ASME B31.1 Embedded Pipe Spools
200	132175-CE01.05	WSPM007262	WECTEC Global Project Services, Inc.	ENERGY STEEL AND SUPPLY CO	Safety-Related Embed Plates and Miscellaneous Steel
201	132176-CE01.05	WSPM007295	WECTEC Global Project Services, Inc.	ENERGY STEEL AND SUPPLY CO	Safety-Related Embed Plates and Miscellaneous Steel
202	J132176-C607.04	WSPM015713	WECTEC Global Project Services, Inc.	ENERGY STEEL AND SUPPLY CO	Fabrication of ASME B31.1 Embedded Pipe Spools
203	4500461828	4500461828	Westinghouse Electric Company LLC	ENERSYS	Non-1E Batteries
204	4500383567	4500383567	Westinghouse Electric Company LLC	ENERSYS DELAWARE INC	Class 1E Battery Cells
205	4500703454	4500703454	Westinghouse Electric Company LLC	ENERSYS DELAWARE INC	Non-1E Batteries
207	4500430528	4500430528	Westinghouse Electric Company LLC	EVOQUA WATER TECHNOLOGIES LLC	BDS Electrodeionization Packages
208	132175-MS08.00	WSPM003989	WECTEC Global Project Services, Inc.	EVOQUA WATER TECHNOLOGIES LLC	CORS
209	132175-MS09.00	WSPM003988	WECTEC Global Project Services, Inc.	EVOQUA WATER TECHNOLOGIES LLC	Demin Water Treatment
210	132175-MS19.00	WSPM003866	WECTEC Global Project Services, Inc.	EVOQUA WATER TECHNOLOGIES LLC	Condensate Polishing Package Unit 3
211	132175-MS30.01	WSPM010466	Stone & Webster Construction Inc	EVOQUA WATER TECHNOLOGIES LLC	Turbine Island Chemical Feed System
212	132176-MS08.00	WSPM003386	WECTEC Global Project Services, Inc.	EVOQUA WATER TECHNOLOGIES LLC	CORS
213	132176-MS09.00	WSPM003385	WECTEC Global Project Services, Inc.	EVOQUA WATER TECHNOLOGIES LLC	Demin Water Treatment

214	132176-MS19.00	WSPM003047	WECTEC Global Project Services, Inc.	EVOQUA WATER TECHNOLOGIES LLC	Condensate Polishing Package Unit4|
215	132176-MS30.01	WSPM010467	Stone & Webster Construction Inc	EVOQUA WATER TECHNOLOGIES LLC	Turbine Island Chemical Feed System
217	4500332459	4500332459	Westinghouse Electric Company LLC	FARRIS ENGINEERING SERVICES	Auxiliary Relief Valves, ASME B16.34
219	4500411181	4500411181	Westinghouse Electric Company LLC	FISHER CONTROLS INTERNATIONAL INC	Air Operated Globe Valves, ASME Sec III Class 1, 2, & 3
220	4500327665	4500327665	Westinghouse Electric Company LLC	FISHER CONTROLS INTL INC	Air Operated Globe Valves, ASME Sec III Class 1, 2, & 3
221	4500338991	4500338991	Westinghouse Electric Company LLC	FISHER CONTROLS INTL INC	Passive Residual Heat Removal Discharge Valves
222	4500352002	4500352002	Westinghouse Electric Company LLC	FISHER CONTROLS INTL INC	Three-Way ASME B16.34 Valves
223	4500371190	4500371190	Westinghouse Electric Company LLC	FISHER CONTROLS INTL INC	Pressurizer Spray Valves
224	132175-MP05.01	WSPM001595	WECTEC Global Project Services, Inc.	FLOWSERVE - NC	MP05.01 Replacement Parts
225	4500328269	4500328269	Westinghouse Electric Company LLC	FLOWSERVE CORP	CVS Makeup Pumps
226	4500328256	4500328256	Westinghouse Electric Company LLC	FLOWSERVE CORP	RNS Centrifugal Normal RHR Pumps
227	4500326442	4500326442	Westinghouse Electric Company LLC	FLOWSERVE CORP - COOKEVILLE TN	Ball and Plug Valves, ASME B16.34
228	4500328752	4500328752	Westinghouse Electric Company LLC	FLOWSERVE CORP - COOKEVILLE TN	Ball and Plug Valves, ASME B16.34
229	4500319052	4500319052	Westinghouse Electric Company LLC	FLOWSERVE CORP - RALEIGH NC	Motor Operated Globe and Gate Valves, ASME Section III, Class 1, 2, & 3
230	4500316051	4500316051	Westinghouse Electric Company LLC	FLOWSERVE CORP - RALEIGH NC	3" & Larger Man Operated Gate, Globe and Check Vlvs, ASME Sec III Cl 1,2,3
231	4500327443	4500327443	Westinghouse Electric Company LLC	FLOWSERVE CORP - RALEIGH NC	Main Steam Isolation Valves (MSIV)
232	4500325750	4500325750	Westinghouse Electric Company LLC	FLOWSERVE CORP - RALEIGH NC	Feedwater Isolation Valves (FWIV)
233	4500328691	4500328691	Westinghouse Electric Company LLC	FLOWSERVE CORP - RALEIGH NC	Feedwater Check Valves (FWCV)
235	4500332338	4500332338	Westinghouse Electric Company LLC	FLOWSERVE CORP - SPRINGVILLE UT	Air Operated Globe Valves, ASME B16.34
236	4500344391	4500344391	Westinghouse Electric	FLOWSERVE CORP -	PCS Recirculation Pumps

			Company LLC	VERNON CA	
237	4500405443	4500405443	Westinghouse Electric Company LLC	FLOWSERVE CORP - VERNON CA	PCS Recirculation Pumps
238	4500354708	4500354708	Westinghouse Electric Company LLC	FLUID HANDLING LLC	SV3 Heat Exchanger, CVS Pump, ME2Q
239	4500331052	4500331052	Westinghouse Electric Company LLC	GARDNER DENVER INC	Liquid Ring Vacuum Pumps (WLS Degasifier Vacuum Pumps)
241	132175-K206.00	WSPM001688	WECTEC Global Project Services, Inc.	GENERAL ATOMICS	Building 305 Radiation Monitors (Area & P/I/G)
242	132175-CR01.07 REL 1	WSPM003255	WECTEC Global Project Services, Inc.	GERDAU INC	Mechanical Splices
243	132175F001701	WSPM011183	Stone & Webster Construction Inc	GERDAU INC	NI-4 Threading Parts for Arnie Uranga
244	132175F001709	WSPM009738	Stone & Webster Construction Inc	GERDAU INC	Chaser for Rodbusters Lenton Chaser set pitt1.25mm art.nr.14900 company Erico
245	132175F002964	WSPM004521	Stone & Webster Construction Inc	GERDAU INC	Training for the rebar threader
246	132175F003565	WSPM010427	Stone & Webster Construction Inc	GERDAU INC	Caps From Gerdau For Thread Protection Nuclear Island Rebar Fab Shop
247	132175F003655	WSPM010444	Stone & Webster Construction Inc	GERDAU INC	Nonpermanent Plant Equiptment For Use On Unit 3 Shield Building. Cadweld Equiptment/No Filler. Per E&DCR SV0-CR01-GEF-000499
248	132175F004067	WSPM010634	Stone & Webster Construction Inc	GERDAU INC	Rebar Threading Machine Replacement Parts. Nuclear Island 3 Rebar Fab Shop.
249	132175F004769	WSPM009901	Stone & Webster Construction Inc	GERDAU INC	Rebar Threading Machine Replacement Parts. Nuclear island 3 Rebar Fab Shop.
250	132175F005480	WSPM009743	WECTEC Global Project Services, Inc.	GERDAU INC	Rebar caps to protect threading at rebar fab shop NI3.
251	132175F005709	WSPM009804	WECTEC Global Project Services, Inc.	GERDAU INC	Rebar Caps For Thread Protection. Nuclear Island 3 Rebar Fab Shop.
252	132175-J400.00	WSPM003744	WECTEC Global Project Services, Inc.	GERDAU INC	Non-Safety Related Rebar and Couplers
253	132176-CR01.04 REL 1	WSPM001207	WECTEC Global Project Services, Inc.	GERDAU INC	Reinforcing Steel (Safety Class C) - Bulk Supply
254	132176-CR01.04-REL02	WSPM003750	WECTEC Global Project Services, Inc.	GERDAU INC	Stock Reinforcing Blanket Purchase Agreement Release #2

255	132176-CR01.04-REL03	WSPM011073	WECTEC Global Project Services, Inc.	GERDAU INC	Stock Bar Release #3
256	132176-J400.00	WSPM003938	WECTEC Global Project Services, Inc.	GERDAU INC	Safety Related Rebar Unit 4
257	J132175-J400A-00	WSPM002104	WECTEC Global Project Services, Inc.	GERDAU INC	Rebar Billets|
258	WVG3000018	WVG3000018	WECTEC Global Project Services, Inc.	GERDAU INC	Thread Chasers For Rebar Threading Machine Nuclear Island 3.
259	WVG3000160	WVG3000160	WECTEC Global Project Services, Inc.	GERDAU INC	Rebar Caps Nuclear Island 3. For Thread Protection.
260	WVG3000206	WVG3000206	WECTEC Global Project Services, Inc.	GERDAU INC	Rebar thread protectors. Nuclear Island 3 Rebar Fab Shop.
261	WVG3000658	WVG3000658	WECTEC Global Project Services, Inc.	GERDAU INC	Rebar thread chasers for rebar threader machine. Fab shop in Nuclear Island 3.
262	WVG3000659	WVG3000659	Stone & Webster Construction Inc	GERDAU INC	Nonpermanent Plant. Construction Aid Material. Nuclear Island 3.
263	WVG3001363	WVG3001363	WECTEC Global Project Services, Inc.	GERDAU INC	to be used for operations of rebar fabrication-safety requirements, used in NOI 6 fabrication shops
264	WVG3001375	WVG3001375	WECTEC Global Project Services, Inc.	GERDAU INC	To be used for operations of rebar fabrication-safety requirement in NOI-6 fabrication shop
265	WVG3001379	WVG3001379	WECTEC Global Project Services, Inc.	GERDAU INC	to be used for operations of rebar fabrication-safety requirement in NOI-6 fabrication shop
266	WVG3001516	WVG3001516	WECTEC Global Project Services, Inc.	GERDAU INC	temporary construction aid to be used in NOI-6 Fabrication Shops, required in operations of the rebar fabrication process.
267	4500620847	4500620847	Westinghouse Electric Company LLC	GRAHAM CORP	RCS Air Ejector Package
268	132175-D100.CA005	WSPM003447	WECTEC Global Project Services, Inc.	GREENBERRY FABRICATION	CA Module Fabrication
269	132175-SS01.39	WSPM000236	WECTEC Global Project Services, Inc.	GREENBERRY FABRICATION	The CH Structural Modules
270	132176-D100.CA005	WSPM003738	WECTEC Global Project Services, Inc.	GREENBERRY FABRICATION	CA Module Fabrication
271	132176-SS01.39	WSPM000829	WECTEC Global Project Services, Inc.	GREENBERRY FABRICATION	The CH Structural Modules

272	4500352740	4500352740	Westinghouse Electric Company LLC	GSE POWER SYSTEMS INC	LSS #1 RFT
274	4500426010	4500426010	Westinghouse Electric Company LLC	GUTOR Electronic LLC	Class 1E Battery Chargers
275	4500456642	4500456642	Westinghouse Electric Company LLC	GUTOR Electronic LLC	Non-1E Battery Chargers
276	4500665006	4500665006	Westinghouse Electric Company LLC	GUTOR Electronic LLC	Non-1E Battery Chargers
277	4500328271	4500328271	Westinghouse Electric Company LLC	HAYWARD TYLER PUMP CO	BDS Stm Gen Drain & Recirc Pump
278	4500359753	4500359753	Westinghouse Electric Company LLC	HOLTEC INTERNATIONAL	Spent Fuel Storage Racks
279	4500449508	4500449508	Westinghouse Electric Company LLC	HOLTEC INTERNATIONAL	Spent Fuel Storage Racks
280	4500450369	4500450369	Westinghouse Electric Company LLC	HOLTEC INTERNATIONAL	Spent Fuel Storage Racks
281	4500459598	4500459598	Westinghouse Electric Company LLC	HOLTEC INTERNATIONAL	Spent Fuel Storage Racks
282	4500652956	4500652956	Westinghouse Electric Company LLC	HYDRATIGHT OPERATION INC	SG Manhole Stud Bolt Tensioner
283	4500365480	4500365480	Westinghouse Electric Company LLC	HYUNDAI HEAVY INDUSTRIES	Feedwater Pump Packages
284	4500654220	4500654220	Westinghouse Electric Company LLC	IHI CORPORATION	Material Consulting Fee
285	4500655276	4500655276	Westinghouse Electric Company LLC	IHI CORPORATION	SV3 Design, Mfg., & Documentation Cost
286	4500705328	4500705328	Westinghouse Electric Company LLC	IHI CORPORATION	Review of Work Package
287	132175-D100.SB008	WSPM003458	WECTEC Global Project Services, Inc.	IHI CORPORATION	Shield Building Conical Roof
288	132176-D100.SB008	WSPM003200	WECTEC Global Project Services, Inc.	IHI CORPORATION	Shield Building Conical Roof
289	132175-MP10.01	WSPM003995	WECTEC Global Project Services, Inc.	ITT GOULDS PUMPS INC	MP10 Pumps MP1G/R/S/T
290	132176-MP10.01	WSPM003391	WECTEC Global Project Services, Inc.	ITT GOULDS PUMPS INC	MP10 Pumps MP1G/R/S/T
291	132176-PH02.02	WSPM003041	WECTEC Global Project Services, Inc.	JAMES C WHITE CO INC	ASME III Tube Track
292	132175-MS02.01	WSPM003994	WECTEC Global Project Services, Inc.	JOHNSON CONTROL CO	Low Capacity (Air Cooled) Chiller
293	132175-MS02.02	WSPM003993	WECTEC Global Project Services, Inc.	JOHNSON CONTROL CO	High Capacity (Air Cooled) Chiller

294	132176-MS02.01	WSPM003390	WECTEC Global Project Services, Inc.	JOHNSON CONTROL CO	Low Capacity (Air Cooled) Chiller
295	132176-MS02.02	WSPM003389	WECTEC Global Project Services, Inc.	JOHNSON CONTROL CO	High Capacity (Air Cooled) Chiller
296	4500416132	4500416132	Westinghouse Electric Company LLC	JOHNSON MARCH SYSTEMS INC	CVS Zinc Injection Package
297	4500371506	4500371506	Westinghouse Electric Company LLC	JOHNSON MARCH SYSTEMS INC	WGS Sample Package
298	4500617215	4500617215	Westinghouse Electric Company LLC	JOHNSON MARCH SYSTEMS INC	Hydrogen Injection Package
299	4500698668	4500698668	Westinghouse Electric Company LLC	JOHNSON MARCH SYSTEMS INC	Panel,Electrohydraulic Control
300	4500626302	4500626302	Westinghouse Electric Company LLC	KTA TATOR INC	Paint Appl Insp Serv Vgtle 4 IIS SPS Cab
301	4500629435	4500629435	Westinghouse Electric Company LLC	KTA TATOR INC	Paint Appl Insp Serv Vgtle 4 IIS SPS Cab
302	4500630383	4500630383	Westinghouse Electric Company LLC	KTA TATOR INC	Paint Appl Insp Serv for Vogtle Unit 4
303	132175-E153.00	WSPM002968	WECTEC Global Project Services, Inc.	LEIDOS ENGINEERING LLC	Engineering Services for Verification & Validation of Standard Plant EFS Design
304	4500379788	4500379788	Westinghouse Electric Company LLC	LHE Co., Ltd.	ME3A Design Analysis Report
305	4500423270	4500423270	Westinghouse Electric Company LLC	LISEGA INC - USA	Reactor Coolant System Support Components Includes: RV, SG, PZR
306	4500435151	4500435151	Westinghouse Electric Company LLC	LISEGA INC - USA	Reactor Coolant System Support Components Includes: RV, SG, PZR
307	132175-C651.03	WSPM010092	Stone & Webster Construction Inc	LISEGA INC - USA	Pipe Support Materials NS related Cat III/E
308	132175-C651.06	WSPM004596	WECTEC Global Project Services, Inc.	LISEGA INC - USA	Lisega Pipe Strap KB04 Mod. WGS Aux
309	132175-PH02.01	WSPM004555	WECTEC Global Project Services, Inc.	LISEGA INC - USA	ASME III Section NF Pipe Supports
310	132175-PH02.03 REL 1	WSPM001655	WECTEC Global Project Services, Inc.	LISEGA INC - USA	ASME III NF Support Material Blanket
311	132175-PH03.01	WSPM004556	WECTEC Global Project Services, Inc.	LISEGA INC - USA	Shop Fabricated ASME B31.1 Pipe Supports - PH03
312	132175-SH60.01	WSPM004665	WECTEC Global Project	LISEGA INC - USA	WEC Safety Class C Pipe Whip

			Services, Inc.		Restraints
313	132175-SS01.34	WSPM003907	WECTEC Global Project Services, Inc.	LISEGA INC - USA	Non-Safety Related Structural Steel Support for Turbine Generator Systems & Aux. Equipment (CRV#1,2,3,4,5,6; MSV/CV#1,2,3,4 and MSR A/B)
314	132176-PH02.01	WSPM004736	WECTEC Global Project Services, Inc.	LISEGA INC - USA	ASME III Section NF Pipe Supports
315	132176-PH03.01	WSPM004735	WECTEC Global Project Services, Inc.	LISEGA INC - USA	Shop Fabricated ASME B31.1 Supports PH03 Large Bore and Small Bore, Seismic and Non Seismic
316	132176-SH60.01	WSPM004676	WECTEC Global Project Services, Inc.	LISEGA INC - USA	WEC Safety Class C Pipe Whip Restraints
317	132176-SS01.34	WSPM003136	WECTEC Global Project Services, Inc.	LISEGA INC - USA	Non-Safety Related Structural Steel Support for Turbine Generator Systems & Aux. Equipment (CRV#1,2,3,4,5,6; MSV/CV#1,2,3,4 and MSR A/B)
318	132175-PY25.01	WSPM003915	WECTEC Global Project Services, Inc.	MACKSON INC	Single Stage, ASME III, Class 1, 2, and 3 Orifices
319	132176-PY25.01	WSPM003033	WECTEC Global Project Services, Inc.	MACKSON INC	Single Stage, ASME III, Class 1, 2, and 3 Orifices
320	132175-C121.12	WSPM015259	Stone & Webster Construction Inc	MACO INC	Fabricated Piping and Loose Materials in Accordance with Shop Fab Piping Spec SV3-GW-P0-007
321	132175-C124.01	WSPM004590	WECTEC Global Project Services, Inc.	MACO INC	Alloy Steel Piping and Fittings for ZRS Diesel Exhaust
322	132175-C810.04	WSPM009793	WECTEC Global Project Services, Inc.	MACO INC	Replacement Anchor Bolt Material for Iso Phase Bus Pedestal
323	132175-CE50.03	WSPM000120	WECTEC Global Project Services, Inc.	MACO INC	Non-Safety Embeds & Misc. Steel Items
324	132175-D220.10	WSPM004531	Stone & Webster Construction Inc	MACO INC	CA Module Lift Frames
325	132175-D220.13	WSPM003455	WECTEC Global Project Services, Inc.	MACO INC	Non-Safety Embedded Plates
326	132175-D500.33	WSPM003372	WECTEC Global Project Services, Inc.	MACO INC	Concrete Chairs For Shield Wall
327	132175-D500.41	WSPM003369	WECTEC Global Project Services, Inc.	MACO INC	Steel, Guardrail, Ladders, Grating For WWRB
328	132175-D500.43	WSPM003368	WECTEC Global Project	MACO INC	Fully Assembled Stair, Grating, And

			Services, Inc.		Steel Beam For Building 315
329	132175F000631A	WSPM004638	Stone & Webster Construction Inc	MACO INC	Module Wall Fit-up
330	132175F004826	WSPM003815	Stone & Webster Construction Inc	MACO INC	Equipment to be used to support the HP Upper/Lower casings for machining repairs
331	132175F005408	WSPM004936	Stone & Webster Construction Inc	MACO INC	Lifting lugs for Turbine Building roof trusses
332	132175F005909	WSPM002999	Stone & Webster Construction Inc	MACO INC	CA01-07 lifting attachment
333	132175F006016	WSPM004720	Stone & Webster Construction Inc	MACO INC	load testing lifting lugs to be used for CA20 installation, work package SV4-CA20-MHH-040
334	132175F006056	WSPM004723	Stone & Webster Construction Inc	MACO INC	Spacer/Shim to be used for temporary use and placed in the RV closure head during the build
335	132176-C121.11	WSPM004907	WECTEC Global Project Services, Inc.	MACO INC	Fabricated Piping & Loose Piping Materials intended for Cat III/SC-E Applications
336	132176-C913.02	WSPM004729	WECTEC Global Project Services, Inc.	MACO INC	Cast Iron Pipe Materials for Unit 4 SDS and Copper Tubing Materials for PWS
337	132176-CE50.03	WSPM003752	WECTEC Global Project Services, Inc.	MACO INC	Non-Safety Embeds & Misc. Steel Items
338	132176-D220.14	WSPM003199	WECTEC Global Project Services, Inc.	MACO INC	Non-Safety Related Embed Plates
339	132176-D500.41	WSPM003196	WECTEC Global Project Services, Inc.	MACO INC	Steel, Guardrail, Ladders, Grating For WWRB
340	132176F000091	WSPM003132	WECTEC Global Project Services, Inc.	MACO INC	Construction aid material to be embedded and left in place and used for course 1 shield building supports, work package SV4-1208-SCW-CV6994
341	132176-FPR134-00074	WSPM003942	WECTEC Global Project Services, Inc.	MACO INC	HYDRO SUPPORT STEEL
342	WVG3001298	WVG3001298	WECTEC Global Project Services, Inc.	MACO INC	Material left in place at Annex 3 Pour Stop WP # SV3-4002-SSW-CV3906
343	WVG3001408	WVG3001408	WECTEC Global Project Services, Inc.	MACO INC	Non-Safety, Non-Permanent plant material needed for Turbine overhead crane test frame-Plate-

					A36 1”x 6” x 8”, QA Category III, Safety Class E, Storage Level D
344	WVG3001471	WVG3001471	WECTEC Global Project Services, Inc.	MACO INC	Load testing of Turbine Island 220 ton O/H crane
345	WVG3001485	WVG3001485	WECTEC Global Project Services, Inc.	MACO INC	TEST WEIGHT BASKET FOR 220 Ton CRANE FOR TI3 MOYA NELSON EXT: 3145
346	4500706639	4500706639	Westinghouse Electric Company LLC	MAGNETROL INTERNATIONAL INC	AP1000 JE27 Radar Level Instruments
347	4500274213	4500274213	Westinghouse Electric Company LLC	MANGIAROTTI SpA	PXS Passive RHR Heat Exchanger
348	4500656971	4500656971	Westinghouse Electric Company LLC	MANGIAROTTI SpA	Pipe Anchors in Brk Exclusion Zone of NI
349	4500278950	4500278950	Westinghouse Electric Company LLC	MANGIAROTTI SpA	PXS Core Makeup Tanks
350	4500273232	4500273232	Westinghouse Electric Company LLC	MANGIAROTTI SpA	PXS Accumulator Tanks
351	4500274162	4500274162	Westinghouse Electric Company LLC	MANGIAROTTI SpA	Pressurizer
352	4500624591	4500624591	Westinghouse Electric Company LLC	MCFARLAND-TRITAN	Lube Oil Jacking Pump Packages
353	132175-MS07.01	WSPM003990	WECTEC Global Project Services, Inc.	MILTON CAT	Diesel Fuel Oil Transfer Packages
354	132175-MS40.01	WSPM003929	WECTEC Global Project Services, Inc.	MILTON CAT	Standby Diesel Generator Units|
355	132176-MS07.01	WSPM003387	WECTEC Global Project Services, Inc.	MILTON CAT	Diesel Fuel Oil Transfer Packages
356	132176-MS40.01	WSPM003046	WECTEC Global Project Services, Inc.	MILTON CAT	Standby Diesel Generator Units|
357	4500430408	4500430408	Westinghouse Electric Company LLC	MIRION TECHNOLOGIES (CONAX NUCLEAR)	Electrical Penetration Assembly
358	4500605776	4500605776	Westinghouse Electric Company LLC	MIRION TECHNOLOGIES (CONAX NUCLEAR)	Containment Vessel
359	4500372803	4500372803	Westinghouse Electric Company LLC	MIRION TECHNOLOGIES (IST) CORP	STND SFTY SR MOD EXCORE DETECTOR ASSY
360	4500670690	4500670690	Westinghouse Electric Company LLC	MIRION TECHNOLOGIES (IST) CORP	Standard Safety Quadaxial Cable - Brown
361	4500709430	4500709430	Westinghouse Electric Company LLC	MIRION TECHNOLOGIES (IST) CORP	AP1000 PR Instrument Well Cap
362	4500709431	4500709431	Westinghouse Electric Company LLC	MIRION TECHNOLOGIES (IST) CORP	AP1000 PR Instrument Well Cap

363	4500642248	4500642248	Westinghouse Electric Company LLC	MOYNO	SV3 WSS Resin Transfer Pump, Pos Disp
364	4500721996	4500721996	Westinghouse Electric Company LLC	NEAL BROTHERS CHARLESTON	Transport & Packaging: PV32/PV33 Valves
365	4500630397	4500630397	Westinghouse Electric Company LLC	NEUGART USA	Reactor Coolant Pump/Motor Maintenance Cart
366	132175-D100.SB003	WSPM003460	WECTEC Global Project Services, Inc.	NEWPORT NEWS INDUSTRIAL CORP	Shield Building
367	132175-D100.SB005	WSPM003459	WECTEC Global Project Services, Inc.	NEWPORT NEWS INDUSTRIAL CORP	Shield Building Air Inlet and Tension Ring
368	132176-D100.SB003	WSPM010835	Stone & Webster Construction Inc	NEWPORT NEWS INDUSTRIAL CORP	Shield Building
369	132176-D100.SB005	WSPM003201	WECTEC Global Project Services, Inc.	NEWPORT NEWS INDUSTRIAL CORP	Shield Building Air Inlet and Tension Ring
370	4500622774	4500622774	Westinghouse Electric Company LLC	NOOK INDUSTRIES INC	Reactor Coolant Pump/Motor Maintenance Cart
371	4500419315	4500419315	Westinghouse Electric Company LLC	NOVA MACHINE PRODUCTS CORP	Spent Fuel Rack Insert for BPRA
372	4500657904	4500657904	Westinghouse Electric Company LLC	NUCLEAR LOGISTICS INC	AP1000 JE49 ElectroMagnetic Flowmeters
373	4500660133	4500660133	Westinghouse Electric Company LLC	NUCLEAR LOGISTICS INC	AP1000 JE26 N1E Ultrasonic Level Sensors
374	4500665052	4500665052	Westinghouse Electric Company LLC	NUCLEAR LOGISTICS INC	AP1000 JE23 Inline Flow Transmitters
375	4500669105	4500669105	Westinghouse Electric Company LLC	NUCLEAR LOGISTICS INC	AP1000 JE52 Pressure & dP Transmitters
376	4500670621	4500670621	Westinghouse Electric Company LLC	NUCLEAR LOGISTICS INC	AP1000 JE36 Process Analyzers
377	4500673034	4500673034	Westinghouse Electric Company LLC	NUCLEAR LOGISTICS INC	AP1000 JE38 Local Process Indicators
378	4500673562	4500673562	Westinghouse Electric Company LLC	OBAYASHI CORP	AP1000 Strategic Planning Team
379	132175-D100.12 RELEASE 1	WSPM014780	WECTEC Global Project Services, Inc.	OFI CUSTOM METAL FABRICATION	Plates For Unassembled OLPs For Civil Modules
380	132175-SS01.00	WSPM003909	WECTEC Global Project Services, Inc.	OWEN INDUSTRIES INC	Safety Related Structural Steel and Steel Decking, Vogtle Unit 3 [Auxiliary and Containment Bldg]
381	132176-SS01.00	WSPM003137	WECTEC Global Project Services, Inc.	OWEN INDUSTRIES INC	Safety Related Structural Steel and Steel Decking, Vogtle Unit 4 [Auxiliary and Containment Bldg]
382	4500332554	4500332554	Westinghouse Electric	PALL CORP - TECH SRVCS	High Pressure Cartridge Filters

			Company LLC		(Reactor Coolant Filters)
383	4500343791	4500343791	Westinghouse Electric Company LLC	PALL CORP - TECH SRVCS	Vogtle 3 - Filter Cartridges
384	4500623272	4500623272	Westinghouse Electric Company LLC	PANELMATIC INC	Engineering Services JR03 Design Changes
385	4500718033	4500718033	Westinghouse Electric Company LLC	PANELMATIC INC	Console,Security Station,CAS
401	4500646466	4500646466	Westinghouse Electric Company LLC	PCI ENERGY SERVICES	PXS Core Makeup Tanks
402	4500710153	4500710153	Westinghouse Electric Company LLC	PCI ENERGY SERVICES LLC	ASME Work for IHP
403	4500435333	4500435333	Westinghouse Electric Company LLC	PENN STATE TOOL & DIE CORP	Wet Annular Burnable Absorber Handling Tool
404	4500455598	4500455598	Westinghouse Electric Company LLC	PENN STATE TOOL & DIE CORP	Fuel Transfer Tube
405	4500616610	4500616610	Westinghouse Electric Company LLC	PENTAIR EQUIPMENT PROTECTION	DOOR ASSY, R HNG, PANTONE 421C, NP
406	4500371198	4500371198	Westinghouse Electric Company LLC	PENTAIR VALVES & CONTROLS US LP	Auxiliary Relief Valves, ASME B16.34
407	4500340946	4500340946	Westinghouse Electric Company LLC	PENTAIR VALVES AND CONTROLS US LP	Auxiliary Relief Valves, ASME Section III Classes 2 and 3
408	4500408943	4500408943	Westinghouse Electric Company LLC	PENTAIR VALVES AND CONTROLS US LP	Vacuum Breaker Vlvs, 1”, CL 150, SST, FI
409	4500341043	4500341043	Westinghouse Electric Company LLC	PENTAIR VALVES AND CONTROLS US LP	Vacuum Breaker Valves, ASME B16.34
410	4500365094	4500365094	Westinghouse Electric Company LLC	PENTAIR VALVES AND CONTROLS US LP	Pressurizer Safety Valves
411	132175-MS60.01	WSPM001583	WECTEC Global Project Services, Inc.	PRECISION BOILERS LLC	Electric Auxiliary Boiler Package
412	4500283276	4500283276	Westinghouse Electric Company LLC	PRECISION CUSTOM COMPONENTS	Reactor Internals
413	132175-MD27.00	WSPM010255	Stone & Webster Construction Inc	PREFERRED METAL TECHNOLOGIES INC	MD27 Safety-Related Gravity/Relief Dampers
414	132176-MD27.00	WSPM010254	Stone & Webster Construction Inc	PREFERRED METAL TECHNOLOGIES INC	MD27 Safety-Related Gravity/Relief Dampers
415	4500312913	4500312913	Westinghouse Electric Company LLC	PREMIER TECHNOLOGY INC	Integrated Head Package
417	4500692319	4500692319	Westinghouse Electric Company LLC	PREMIER TECHNOLOGY INC	Reactor Cavity Seal Ring
418	4500630606	4500630606	Westinghouse Electric Company LLC	PREMIER TECHNOLOGY INC	Reactor Vessel Internals Lifting Rig

420	4500714777	4500714777	Westinghouse Electric Company LLC	PRYSMIAN COMMUNICATIONS CABLES	CABLE, FIBER OPTIC 24X50/125UM MM BLK
421	4500612168	4500612168	Westinghouse Electric Company LLC	QUALTECH NP	Spent Fuel System Gates
422	4500708614	4500708614	Westinghouse Electric Company LLC	RDF CORP	AP1000 JE32 Resistance Temp Detectors
423	4500639279	4500639279	Westinghouse Electric Company LLC	REMOTE OCEAN SYSTEMS INC	FHS Underwater Camera Equipment
424	4500616098	4500616098	Westinghouse Electric Company LLC	ROLLS-ROYCE CIVIL NUCLEAR CANADA LT	Filter Transfer Casks
426	4500436941	4500436941	Westinghouse Electric Company LLC	RUMSEY ELECTRIC CO	Electrical Protection Relay Panels
427	4500319424	4500319424	Westinghouse Electric Company LLC	SAMSHIN LIMITED	1” & 2” Manually Operated Globe and Check Valves, ASME Sec III Cl 1, 2, & 3
428	4500418139	4500418139	Westinghouse Electric Company LLC	SAMSHIN LIMITED	Motor Operated Gate and Globe Valves, ASME B16.34
429	4500309569	4500309569	Westinghouse Electric Company LLC	SAMSHIN LIMITED	1” & 2” Manually Operated Globe and Check Valves, ASME B16.34
430	4500325899	4500325899	Westinghouse Electric Company LLC	SAMSHIN LIMITED	3” & Larger Manually Operated Gate, Globe, & Check Vlvs, ASME B16.34
434	4500409603	4500409603	Westinghouse Electric Company LLC	SENIOR FLEXONICS PATHWAYS	Containment Piping Penetrations with Flued Heads
435	4500674167	4500674167	Westinghouse Electric Company LLC	SENIOR FLEXONICS PATHWAYS	Joint,Expansion,10”,SST
436	4500674873	4500674873	Westinghouse Electric Company LLC	SENIOR FLEXONICS PATHWAYS	Applicable Document Revisions
437	132176-PY20.00	WSPM010307	Stone & Webster Construction Inc	SENIOR FLEXONICS PATHWAYS	PY20 Metallic Expansion Joints
438	4500347757	4500347757	Westinghouse Electric Company LLC	SENTRY EQUIPMENT CORP	WGS Gas Cooler
439	4500404005	4500404005	Westinghouse Electric Company LLC	SENTRY EQUIPMENT CORP	Resin Sampler Package
440	4500378131	4500378131	Westinghouse Electric Company LLC	SENTRY EQUIPMENT CORP	PSS Grab Sampling Unit
441	4500312932	4500312932	Westinghouse Electric Company LLC	SHARPSVILLE CONTAINER	Chemical Feed Tank
442	4500315960	4500315960	Westinghouse Electric Company LLC	SHARPSVILLE CONTAINER	WGS Delay Bed

443	4500282878	4500282878	Westinghouse Electric Company LLC	SIEMENS INDUSTRY INC	RCP Variable Frequency Drives, 6.9 kV, 60 Hz Input
444	4500412943	4500412943	Westinghouse Electric Company LLC	SIEMPELKAMP NUCLEAR SERVICES	Hydrogen Recombiners
445	4500663496	4500663496	Westinghouse Electric Company LLC	SPRAYING SYSTEMS CO	Spent Fuel Pool Spray Nozzles
446	4500298889	4500298889	Westinghouse Electric Company LLC	SPX CORP COPES VULCAN OPERATION	Squib Valve
447	4500688697	4500688697	Westinghouse Electric Company LLC	STANEX, LLC	Structural Stability Analysis
448	132175-SS01.02	WSPM003908	WECTEC Global Project Services, Inc.	STEELFAB INC	Non-Safety Related Structural Steel and Decking
449	132176-SS01.02	WSPM010256	Stone & Webster Construction Inc	STEELFAB INC	Non-Safety Related Structural Steel and Decking
450	4500630430	4500630430	Westinghouse Electric Company LLC	STRAINSERT CO	Reactor Coolant Pump/Motor Maintenance Cart
451	132176-MP10.00	WSPM010411	Stone & Webster Construction Inc	SULZER PUMPS US INC	Turbine Building Closed Cooling Water System (TCS) Pumps (MP1H)
452	4500367194	4500367194	Westinghouse Electric Company LLC	SWAGELOK CAPITAL PROJECTS COMPANY	Instrumentation Valves, Safety Related
453	4500459975	4500459975	Westinghouse Electric Company LLC	SWAGELOK CAPITAL PROJECTS COMPANY	Needle Valves
454	4500370661	4500370661	Westinghouse Electric Company LLC	SWAGELOK CAPITAL PROJECTS COMPANY	Mechanical Connections/Quick Disconnects
455	4500601068	4500601068	Westinghouse Electric Company LLC	SWAGELOK CAPITAL PROJECTS COMPANY	Mechanical Connections/Quick Disconnects
456	132175-JT01.02	WSPM007192	Stone & Webster Construction Inc	SWAGELOK NORTH CAROLINA	ASME III Tube Fittings
457	132175-JZ01.01	WSPM003790	WECTEC Global Project Services, Inc.	SWAGELOK NORTH CAROLINA	Instrumentation Valve Manifolds, ASME Section III, Class 2 and 3 for Various Systems
458	132176-JT01.02	WSPM007241	Stone & Webster Construction Inc	SWAGELOK NORTH CAROLINA	ASME III Tube Fittings
459	132176-JZ01.01	WSPM003936	WECTEC Global Project Services, Inc.	SWAGELOK NORTH CAROLINA	Instrumentation Valve Manifolds, ASME Section III, Class 2 and 3 for Various Systems
460	4500449494	4500449494	Westinghouse Electric Company LLC	TAYCO ENGINEERING INC	Hydrogen Igniters
461	4500608824	4500608824	Westinghouse Electric Company LLC	THE CALVERT CO INC	SV3 Repl. EB04 Gaskets and Adhesive Mat.

462	4500639965	4500639965	Westinghouse Electric Company LLC	THE HILLIARD CORP	Oil Flushing Unit
463	4500269770	4500269770	Westinghouse Electric Company LLC	TIOGA PIPE SUPPLY CO INC	Reactor Coolant Loop Piping
464	4500318727	4500318727	Westinghouse Electric Company LLC	TOSHIBA AMERICA NUCLEAR ENERGY CORP	Main Step-up Transformers
465	4500416115	4500416115	Westinghouse Electric Company LLC	TRANSCO PRODUCTS INC	Metal Reflective Insulation (SGs, RCPs, PZR, RCL Pipe) To be installed by Vendor
466	4500416114	4500416114	Westinghouse Electric Company LLC	TRANSCO PRODUCTS INC	RV Head Metal Reflective Ins. (includes IHP and RV Flange Ins.) To be installed by Vendor
467	4500416113	4500416113	Westinghouse Electric Company LLC	TRANSCO PRODUCTS INC	Metal Reflective Insulation (Other than MN01, MN03, MN20) To be installed by Vendor
468	4500416112	4500416112	Westinghouse Electric Company LLC	TRANSCO PRODUCTS INC	RV Insulation System (also called Reactor Cavity Insulation) To be installed by Vendor
469	4500318072	4500318072	Westinghouse Electric Company LLC	TRANTER INC	WLS Liquid Seal Water Heat Exchangers
470	4500409669	4500409669	Westinghouse Electric Company LLC	TRI NUCLEAR CORP	Skimmer / Strainers
471	4500695504	4500695504	Westinghouse Electric Company LLC	TRICO WELDING CO	Reactor Coolant Pump/Motor Maintenance Cart
472	4500682637	4500682637	Westinghouse Electric Company LLC	TRICO WELDING CO	Reactor Upper Internals Storage Stand
473	4500680745	4500680745	Westinghouse Electric Company LLC	TRICO WELDING CO	FOOT,LEVELING,IGA LIFT RIG, - Vogtle
474	4500326440	4500326440	Westinghouse Electric Company LLC	TSM TECH CO LTD	BDS Steam Generator Blowdown Heat Exchangers
475	4500340572	4500340572	Westinghouse Electric Company LLC	TSM TECH CO LTD	CVS Mixed Bed and Cation Demineralizers
476	4500452899	4500452899	Westinghouse Electric Company LLC	TSM TECH CO LTD	Reactor Coolant Depressurization Sparger
477	4500707362	4500707362	Westinghouse Electric Company LLC	TURNER INDUSTRIES GROUP LLC	AP1000 Services for Program Stand-Up
478	132175-PL02.05	WSPM007191	WECTEC Global Project Services, Inc.	TURNER INDUSTRIES GROUP LLC	Shop Fabrication of ASME III Piping Subassemblies
479	132176-PL02.05	WSPM007240	WECTEC Global Project Services, Inc.	TURNER INDUSTRIES GROUP LLC	Shop Fabrication of ASME III Piping Subassemblies

480	4500656664	4500656664	Westinghouse Electric Company LLC	TW METALS	PXS Core Makeup Tanks
481	4500428822	4500428822	Westinghouse Electric Company LLC	VAL FAB INC	SV3Tank, Batching, Boric Acid, CVS, 60hz
482	4500325905	4500325905	Westinghouse Electric Company LLC	VAL FAB INC	SV4 WLS Degasifier Separator MV7J
483	4500375201	4500375201	Westinghouse Electric Company LLC	VAL FAB INC	Spent Resin Tanks (with Internal Eductors and Screens)
484	4500374238	4500374238	Westinghouse Electric Company LLC	VALCOR ENGINEERING CORP	Solenoid-Operated Globe Valves, ASME Section III Classes 1, 2, and 3
486	4500433665	4500433665	Westinghouse Electric Company LLC	VALCOR ENGINEERING CORP	Pressure Regulating Globe Valves, ASME Section III Classes 2 and 3
487	4500602331	4500602331	Westinghouse Electric Company LLC	VALCOR ENGINEERING CORP	Solenoid-Operated Globe Valves, ASME B16.34
489	4500677839	4500677839	Westinghouse Electric Company LLC	VALCOR ENGINEERING CORP	Cavitating Venturis
491	4500677834	4500677834	Westinghouse Electric Company LLC	VALCOR ENGINEERING CORP	Letdown Orifice
492	4500676913	4500676913	Westinghouse Electric Company LLC	VALCOR ENGINEERING CORP	Plug-Resistant Orifices, ASME Section III
494	4500640482	4500640482	Westinghouse Electric Company LLC	VALCOR ENGINEERING CORP	Safety-Related Eductors
496	132175-D100.CA011	WSPM003465	WECTEC Global Project Services, Inc.	VIGOR	CA01 Book II Component Fabrication
497	132175-D100.CA015	WSPM003464	WECTEC Global Project Services, Inc.	VIGOR	Select CH Modules Fabrication
498	132175-D100.CB002	WSPM003462	WECTEC Global Project Services, Inc.	VIGOR	CB20 Module Design Package
499	132175-G230.M06	WSPM010862	WECTEC Global Project Services, Inc.	VIGOR	Non-Safety Related Mechanical Modules
500	132176-D100.CA011	WSPM010674	Stone & Webster Construction Inc	VIGOR	CA20 Module Fabrication
501	132176-D100.CA015	WSPM003736	WECTEC Global Project Services, Inc.	VIGOR	Select CH Modules Fabrication
502	132176-D100.CB002	WSPM003742	WECTEC Global Project Services, Inc.	VIGOR	CB20 Module Design Package
503	132176-G230.M06	WSPM010863	WECTEC Global Project Services, Inc.	VIGOR	Non-Safety Related Mechanical Modules
504	4500455911	4500455911	Westinghouse Electric Company LLC	VIRGINIA TRANSFORMER	Excitation Transformer

505	4500313659	4500313659	Westinghouse Electric Company LLC	WARREN RUPP INC	Air-Operated (Pneumatic) Double Diaphragm Pumps (22 pumps - not listed individually)
506	4500467904	4500467904	Westinghouse Electric Company LLC	WEED INSTRUMENT DBA ULTRA ELECTRONI	JE02 Press / Diff. Press Transmitters
507	4500668665	4500668665	Westinghouse Electric Company LLC	WEED INSTRUMENT DBA ULTRA ELECTRONI	AP1000 JE03 Primary Temperature Elements
508	4500698276	4500698276	Westinghouse Electric Company LLC	WEED INSTRUMENT DBA ULTRA ELECTRONI	AP1000 JE47 HVAC Specialty Instruments
509	4500712520	4500712520	Westinghouse Electric Company LLC	WEED INSTRUMENT DBA ULTRA ELECTRONI	AP1000 JE47 HVAC Specialty Instruments
510	4500713925	4500713925	Westinghouse Electric Company LLC	WEED INSTRUMENT DBA ULTRA ELECTRONI	AP1000 JE47 HVAC Specialty Instruments
511	4500655653	4500655653	Westinghouse Electric Company LLC	WEED INSTRUMENT DBA ULTRA ELECTRONI	Thermowell,4.5”,RTD,SS,ASME III-Class 3
512	4500370608	4500370608	Westinghouse Electric Company LLC	WEIR VALVE & CONTROLS USA INC	Fuel Transfer Tube Gate Valve
514	4500309727	4500309727	Westinghouse Electric Company LLC	WEIR VALVE & CONTROLS USA INC	Butterfly Valves, ASME Section III Classes 2 and 3
515	4500419078	4500419078	Westinghouse Electric Company LLC	WEIR VALVE & CONTROLS USA INC	Air Operated Globe Valves, ASME Sec III Class 1, 2, & 3
517	4500319090	4500319090	Westinghouse Electric Company LLC	WEIR VALVE & CONTROLS USA INC	Butterfly Valves, ASME B16.34
518	4500377559	4500377559	Westinghouse Electric Company LLC	WEIR VALVE & CONTROLS USA INC	Extraction Steam Non-Return Valves
519	132175-VW01.00-RELEASE1	WSPM004664	Stone & Webster Construction Inc	WELDSTAR	ASME III Weld Filler Material, Weldstar Blanket Order
520	4500693471	4500693471	Westinghouse Electric Company LLC	WESCO DISTRIBUTION INC	Plate,Mounting, ET03 Trans, NGR Mod.
530	132175-DF01.01	WSPM003365	WECTEC Global Project Services, Inc.	WESTINGHOUSE ELECTRIC CO LLC	Class 1E Fused Transfer Switch Boxes
531	132175-DF03.01	WSPM003364	WECTEC Global Project Services, Inc.	WESTINGHOUSE ELECTRIC CO LLC	Class 1E Spare Battery Term Boxes (DF03 - Aux)
532	132175-DS01.01	WSPM003363	WECTEC Global Project Services, Inc.	WESTINGHOUSE ELECTRIC CO LLC	Class 1E 250 VDC Switchboards
533	132175-EA01.01	WSPM002965	WECTEC Global Project Services, Inc.	WESTINGHOUSE ELECTRIC CO LLC	Distribution Panels, 1E, 120 & 208 VAC 60Hz
534	132175-EA03.01	WSPM002954	WECTEC Global Project Services, Inc.	WESTINGHOUSE ELECTRIC CO LLC	Fuse Panels, 1E, 120 VAC 60Hz
535	132175-EJ01.01	WSPM002950	WECTEC Global Project Services, Inc.	WESTINGHOUSE ELECTRIC CO LLC	Class 1E Junction Boxes

536	132176-DF01.01	WSPM003193	WECTEC Global Project Services, Inc.	WESTINGHOUSE ELECTRIC CO LLC	Class 1E Fused Transfer Switch Boxes
537	132176-DF03.01	WSPM003192	WECTEC Global Project Services, Inc.	WESTINGHOUSE ELECTRIC CO LLC	Class 1E Spare Battery Term Boxes (DF03 - Aux)
538	132176-DS01.01	WSPM003191	WECTEC Global Project Services, Inc.	WESTINGHOUSE ELECTRIC CO LLC	Class 1E 250 VDC Switchboards
539	132176-EA01.01	WSPM003187	WECTEC Global Project Services, Inc.	WESTINGHOUSE ELECTRIC CO LLC	Distribution Panels, 1E, 120 & 208 VAC 60Hz
540	132176-EA03.01	WSPM003185	WECTEC Global Project Services, Inc.	WESTINGHOUSE ELECTRIC CO LLC	Fuse Panels, 1E, 120 VAC 60Hz
541	132176-EJ01.01	WSPM003112	WECTEC Global Project Services, Inc.	WESTINGHOUSE ELECTRIC CO LLC	Class 1E Junction Boxes
542	132176-G230.M07	WSPM001256	WECTEC Global Project Services, Inc.	WESTINGHOUSE ELECTRIC CO LLC	Non-Safety Related Mechanical Modules
543	132175-MS90.01	WSPM001582	WECTEC Global Project Services, Inc.	MILTON CAT	Ancillary Diesel Generators
544	132176-JT01.01	132176-JT01.01	WECTEC Global Project Services, Inc.	Dubose National Energy Services INC	ASME III Tubing
545	4500332480	4500332480	Westinghouse Electric Company LLC	Swagelok	Vogtle Project, Units 3 and 4, PV47, Instrumentation Valves, Non-Safety Related
546	4500672734	4500672734	Westinghouse Electric Company LLC	Ben Franklin Design	Restrictor Plate Assembly Panels and Parts
547	4500700158	4500700158	Westinghouse Electric Company LLC	PCI Energy Services	UT INSP. OF NF SUPPORTS AT VOGTLE 3-4
548	4500677532	4500677532	Westinghouse Electric Company LLC	PREMIER TECHNOLOGY INC	Premier - Vogtle - VH01- SGTIS-U Refurbishment
549	132175-C802.09	132175-C802.09	WECTEC Global Project Services, Inc.	Mackson	B31.1 Bolts Safety D
550	132175-D500.50	132175-D500.50	WECTEC Global Project Services, Inc.	HILTI INC	Hilti H-D Supports
551	132175-FPR12-01836-1	WSPM013138	WECTEC Global Project Services, Inc.	LINCOLN ELECTRIC COMPANY	ASME III Weld Filler Metal
552	132175-FPR12-01836-10	WSPM004541	WECTEC Global Project Services, Inc.	LINCOLN ELECTRIC COMPANY	ASME III Weld Filler Metal
553	132175-FPR12-01836-11	WSPM004542	WECTEC Global Project Services, Inc.	LINCOLN ELECTRIC COMPANY	ASME III Weld Filler Metal
554	132175-FPR12-01836-2	WSPM010271	WECTEC Global Project Services, Inc.	LINCOLN ELECTRIC COMPANY	ASME III Weld Filler Metal
555	132175-FPR12-01836-4	WSPM004543	WECTEC Global Project Services, Inc.	LINCOLN ELECTRIC COMPANY	ASME III Weld Filler Metal

556	132175-FPR12-01836-5	WSPM004544	WECTEC Global Project Services, Inc.	LINCOLN ELECTRIC COMPANY	ASME III Weld Filler Metal
557	132175-FPR12-01836-7	WSPM004546	WECTEC Global Project Services, Inc.	LINCOLN ELECTRIC COMPANY	ASME III Weld Filler Metal
558	132175-FPR12-01836-8	WSPM004547	WECTEC Global Project Services, Inc.	LINCOLN ELECTRIC COMPANY	ASME III Weld Filler Metal
559	132175-FPR12-01836-9	WSPM004548	WECTEC Global Project Services, Inc.	LINCOLN ELECTRIC COMPANY	ASME III Weld Filler Metal
560	132175-FPR12-01834-00	132175-FPR12-01834-00	WECTEC Global Project Services, Inc.	LINCOLN ELECTRIC COMPANY	ASME III Weld Filler Metal
561	4500411985	4500411985	Westinghouse Electric Company LLC	GA PORTS AUTHORITY	Shield Building Logistics
564	4500708616	4500708616	Westinghouse Electric Company LLC	NEFAB PACKAGING NORTH EAST LLC	Crating, skids and packaging
567	4500635130	4500635130	Westinghouse Electric Company LLC	DUVAL PRECISION GRINDING INC	Grind alignment plate
568	4500608147	4500608147	Westinghouse Electric Company LLC	INDUSTRIAL TESTING LAB SERV	Cleaning procedure testing
569	4500663124	4500663124	Westinghouse Electric Company LLC	B&G MANUFACTURING CO INC	Fasteners
570	4500671102	4500671102	Westinghouse Electric Company LLC	FH PETERSON MACHINE CORP	OSV Machine
571	4500677611	4500677611	Westinghouse Electric Company LLC	FLETCH'S SANDBLASTING	Header Piping End Frame Coating
576	4500723822	4500723822	Westinghouse Electric Company LLC	ENERGY AND PROCESS CORP	Shim R.S.
577	4500723651	4500723651	Westinghouse Electric Company LLC	KAUFMAN CO	Air Tank Paint Part A
578	4500721313	4500721313	Westinghouse Electric Company LLC	NEFAB PACKAGING NORTH EAST LLC	SCS COLUMNS SKID & BOX
579	4500650880	4500650880	Westinghouse Electric Company LLC	DUBOSE NATIONAL ENERGY SERVICES INC	Washer
580	4500395458	4500395458	Westinghouse Electric Company LLC	NUCRANE MANUFACTURING LLC	Update PO 4500395458 (U4)
581	4500395460	4500395460	Westinghouse Electric Company LLC	NUCRANE MANUFACTURING LLC	Cask Crane Unit 3 Rework per PIN 4
582	4500422058	4500422058	Westinghouse Electric Company LLC	NUCRANE MANUFACTURING LLC	NuCrane PINs 1&2, Vogtle 15 Ton U4
583	4500430190	4500430190	Westinghouse Electric Company LLC	NUCRANE MANUFACTURING LLC	VOG HH U3 Rework per PIN 001
584	4500600930	4500600930	Westinghouse Electric	NUCRANE	NuCrane VG U4 20T Pin 0006

			Company LLC	MANUFACTURING LLC	(45006000930)
588	4500722525	4500722525	Westinghouse Electric Company LLC	STRAINSERT CO	PIN; LOAD CELL, UPPER BLOCK, AUX HOIST,
590	4500723050	4500723050	Westinghouse Electric Company LLC	ARROW TANK AND ENGINEERING CO INC	Storage of PR-10-0360-U3
600	4500698454	4500698454	Westinghouse Electric Company LLC	INDEPENDENT PACKING SERVICES	Preventative Maintenance for Polar
601	4500707952	4500707952	Westinghouse Electric Company LLC	INDEPENDENT PACKING SERVICES	Polar Rail Crating Labor
602	4500718445	4500718445	Westinghouse Electric Company LLC	INDEPENDENT PACKING SERVICES	Crating Labor for VOG3 Polar Crane
604	4500719569	4500719569	Westinghouse Electric Company LLC	INDEPENDENT PACKING SERVICES	On-Site Packaging
608	4500723299	4500723299	Westinghouse Electric Company LLC	INDUSTRIAL PAINTING SPECIALIST	Blast and Paint girder A
610	4500723864	4500723864	Westinghouse Electric Company LLC	INDEPENDENT PACKING SERVICES	On-Site Packaging
611	J132175-FPR12-01834-00	WSPM010400	WECTEC Global Project Services, Inc.	LINCOLN ELECTRIC COMPANY	ASME III Weld Filler Material
612	132175-C825.S03	WSPM004594	Stone & Webster Construction Inc	LINCOLN ELECTRIC COMPANY	ASME III WELD MATERIAL
613	4500719651	4500719651	Westinghouse Electric Company LLC	LYNX TECHNOLOGY PARTNERS INC	CDKSM-1Yr
614	4500400518	4500400518	Westinghouse Electric Company LLC	SHAW NUCLEAR SERVICES INC	procurement of R365 for Vogtle
615	4500404540	4500404540	Westinghouse Electric Company LLC	SHAW NUCLEAR SERVICES INC	Procurement of Q240 for Vogtle
616	4500406088	4500406088	Westinghouse Electric Company LLC	SHAW NUCLEAR SERVICES INC	Vogtle - Transfer of Q305 Design Doc.
617	4500419771	4500419771	Westinghouse Electric Company LLC	SHAW NUCLEAR SERVICES INC	Procurement of Q223 for Vogtle
618	4500419776	4500419776	Westinghouse Electric Company LLC	SHAW NUCLEAR SERVICES INC	Procurement of Q233 for Vogtle
619	4500388070	4500388070	Westinghouse Electric Company LLC	DRS CONSOLIDATED CONTROLS INC	Vogtle 3 Phase Reference Sensors (4)
620	132175-D500.25	132175-D500.25	WECTEC Global Project Services, Inc.	Chatham Steel Corporation	Stainless Steel Plate For KB10 Module
621	132175-D500.21	132175-D500.21	WECTEC Global Project Services, Inc.	Consolidated Power Supply a Div of	Replacement Plates for OLP's in CA20 Module
622	132176-G230.01	WSPM010836	WECTEC Global Project Services, Inc.	Precision Boilers LLC	Electric Auxiliary Boiler Package|

623	132175-G230.01	WSPM010833	WECTEC Global Project Services, Inc.	Precision Boilers LLC	Electric Auxiliary Boiler Package|
624	4500699704	4500699704	Westinghouse Electric Company LLC	SARGENT & LUNDY	Fixed Labor Rate 11 Pers.
625	132175-PY51.00	132175-PY51.00	WECTEC Global Project Services, Inc.	Senior Flexonics	Flexible Hoses
626	132176-PY51.00	132176-PY51.00	WECTEC Global Project Services, Inc.	Senior Flexonics	Flexible Hoses
627	132176-D100.CA010	132176-D100.CA010	WECTEC Global Project Services, Inc.	Specialty Maintenance & Construction Inc	CA20 Module Fabrication
628	4500467735	4500467735	Westinghouse Electric Company LLC	NUCLEAR LOGISTICS INC	Testing
629	4500710159	4500710159	Westinghouse Electric Company LLC	NUCLEAR LOGISTICS INC	JE26 Ultrasonic Testing
630	4500715247	4500715247	Westinghouse Electric Company LLC	NUCLEAR LOGISTICS INC	JE27 Testing
631	789426	789426	CB&I, Inc.	WECTEC Global Project Services, Inc.	MC Parts

EXHIBIT I

RATES FOR LEASED EQUIPMENT

WESTINGHOUSE CONSTRUCTION EQUIPMENT
EQUIPMENT DAILY RATE PRICING SHEET
APRIL 2017

Rate Group	Rate Group Description	Daily Rate
A01	GRPLR HYDR ROTATING DRUM/DEBRIS (320)	[***]
A03	SHEARS HYDR - 200 TON (320)	[***]
A05	CONCRETE CRUSHER	[***]
A06	HYDRAULIC HO-RAM (320)	[***]
A13	EVERGREEN BUCKET SCALE FOR LOADER	[***]
A17	PULL BEHIND BOX GRADER	[***]
A18	ROOT RAKE FOR D6 DOZER	[***]
A19	DISK HARROW	[***]
A21	BROOM ATTACHMENT FOR L120	[***]
A23	MATERIAL HANDLING ARM	[***]
A24	‘14’ SNOW BLADE FOR WHEEL LOADER	[***]
A27	60” TILT BUCKET FOR 320	[***]
A28	HYDRAULIC BROOM FOR CAT 287C	[***]
A31	SCRAP MAGNET, 46”	[***]
B40	CONSTR & BREATHING AIR COMPRESSORS	[***]
B57	AIR COMPRESSOR - 1-50 CFM SCROLL	[***]
B60	AIR COMPRESSOR, QSI 1000	[***]
B61	AIR TANK - 660 GALLON	[***]
B62	AIR TANK - 2000 GALLON	[***]
C01	BAR SPREADER	[***]
C02	MAN BASKET FOR CRANE	[***]
C06	AIR COMPRESSOR 185 CFM	[***]
C08	AIR COMPRESSOR 375 CFM	[***]
C09	AIR COMPRESSOR, ELEC 215 CFM	[***]
C12	DETECTOR, HOLIDAY	[***]
C21	FORKLIFT - WAREHOUSE 5K-6K#	[***]
C24	CRANE, 17 TON TRUCK MOUNT	[***]
C25	LUFFING JIB	[***]
C27	CRANE, 8.2 TON CARRY DECK	[***]
C28	CRANE, 15 TON ROUGH TERRAIN	[***]

C29	CRANE, 15 TON CARRY DECK	[***]
C33	CRANE, 60 TON ROUGH TERRAIN	[***]
C39	90 TON ROUGH TERRAIN CRANE	[***]
C40	CRANE, 150 TON ROUGH TERRAIN	[***]
C41	CRANE, 130 TON ROUGH TERRAIN	[***]
C42	CRANE, 220 TON LATTICE BOOM	[***]
C43	CRANE, 300 TON LATTICE BOOM	[***]
C47	WELDER 400 AMP DIESEL	[***]
C53	COMPACTOR	[***]
C55	PIPE THREADER	[***]
C57	BRIDGE CRANE	[***]
C64	BUS, SHORT, 14 PASSENGER	[***]
C68	BUS PASSENGER	[***]
C69	CAR	[***]
C70	EXECUTIVE VEHICLE	[***]
C71	SPOTTING TRACTOR 93 COMMANDO	[***]
C76	SHUTTLE BUS	[***]
C81	OPTICAL LEVEL	[***]
C84	DUAL DRUM AIR WINCH, 10K	[***]
C86	CABLE TUGGER, 10K # PNEUMATIC WINCH	[***]
C87	LASER ALIGNMENT SYSTEM	[***]
C88	PORTABLE METAL BUILDING	[***]
C90	INSPECTION SYSTEM PROBE	[***]
C99	BENDER, CUTTER	[***]
E00	BACKHOE/90HP/4WD/EXT	[***]
E01	BACKHOE/90HP/2WD/EXT	[***]
E03	DOZER/90HP/STD	[***]
E04	DOZER/110HP/LGP	[***]
E05	DOZER/140HP/LGP	[***]
E07	DOZER/75HP/XL	[***]
E08	DOZER/185HP/LGP	[***]
E10	GRADER/215HP/14’ BLADE	[***]
E12	EXCAVATOR/8METRIC TON	[***]
E13	EXCAVATOR/20 METRIC TON	[***]
E14	EXCAVATOR/30 METRIC TON	[***]
E15	EXCAVATOR/REMOTE CONTROL BROKK 400	[***]
E16	FORKLIFT/HI REACH/10-12K	[***]
E18	DUMP/OFF ROAD/30 TON	[***]
E19	DUMP/OFF ROAD/35 TON	[***]

E21	WHEEL LOADER/3.5 YD	[***]
E26	WHEEL LOADER/5-7 YD	[***]
E28	TRACKMOBILE	[***]
E29	WATER TRUCK/OFF ROAD/5-7K	[***]
E31	VIB SOIL COMPACTOR/84”	[***]
E34	33” REMOVE TRENCH COMPACTOR	[***]
E36	KUBOTA TRACTOR	[***]
E37	15 TON FORKLIFT	[***]
E38	INDUSTRIAL FORKLIFT 9000#	[***]
E39	MINI TRACK LOADER	[***]
E41	SRAIGHT MAST FORKLIFT 26 TON	[***]
E42	SELF-CONTAINED BROOM	[***]
E43	60” ZERO TURN MOWER	[***]
E46	STREET SWEEPER, TRUCK MOUNTED	[***]
E51	275HP AG TRACTOR W/DISC	[***]
F06	AIR STRIPPER, LOW PROFILE	[***]
F11	CLARIFIER LAMELLA TRLR MOUNTED	[***]
F15	FILTER LIQUID DUAL CELL SKID	[***]
F16	FILTER LIQUID SINGLE CELL SKID	[***]
F19	FILTER LIQUID IN-LINE BAG	[***]
F20	PORTABLE POOL - 12000 GAL	[***]
F24	KNOCKOUT TANK	[***]
F25	FILTER VAPOR PHASE CARBON (DUAL CELL)	[***]
F26	FILTER VAPOR PHASE CARBON (SINGLE CELL)	[***]
F28	VAPOR PHASE CARBON CELL, 2000#	[***]
F33	SOIL VAPOR EXTRACTION <25 HP SKID (SVE)	[***]
F34	SOIL VAPOR EXTRACTION 25 HP SKID (SVE)	[***]
F35	SOIL VAPOR EXTRACTION 75 HP SKID (SVE)	[***]
F46	COOLING TOWER	[***]
F48	6 LINE BAG FILTER	[***]
F49	FILTER LIQUID 2000# CAPACITY	[***]
G03	GENERATOR 50-75 KW	[***]
G08	GENERATOR 75-100 KW	[***]
G09	GENERATOR, 40-50KW	[***]
H36	PRESSURE LOGGER	[***]
H37	RUGGED READER LOAD-UP	[***]
H39	MOTION RUGGEDIZED DATA COLLECTOR	[***]
H40	HAND-HELD WATER SURVEYOR	[***]
H42	YSI 600 SONDE D/H WATER SURVEYOR	[***]

H43	YSI 6820/6920 SONDE D/H WATER SURVEYOR	[***]
H44	WATER SURVEYOR W/BLUETOOTH	[***]
H48	ULTRA SONIC FLOW METER	[***]
J06	FERROSCAN SYSTEM FOR REBAR	[***]
J07	GCS 900 GPS FOR EXCAVATOR	[***]
J09	REPEATER FOR GPS SYSTEM	[***]
J10	RTK 900 BASE AND ROVER	[***]
J11	GPS ROVER	[***]
J12	GCS 900 GPS MACHINE CONTROL	[***]
J16	HAND HELD GPS LOW ACCURACY	[***]
J17	HAND HELD GPS HIGH ACCURACY	[***]
J18	HAND HELD GPS GIS ACCURACY	[***]
J20	HIGH RESOLUTION METAL DETECTOR	[***]
J21	TOTAL ROBOTIC SURVEY STATION	[***]
J26	TOTAL SURVEY SYSTEM	[***]
J27	LASER LEVEL	[***]
J28	PIPE LASER	[***]
J30	3D SCANNER W/LDAR	[***]
J40	MAGNETOMETER, UNDERWATER	[***]
K06	FIT TESTER 8020 PORTACOUNT	[***]
K07	PUF AIR SAMPLER	[***]
K08	TSP AIR SAMPLER	[***]
K09	PM10 AIR SAMPLER	[***]
K11	LAPEL AIR SAMPLER	[***]
K12	AIR FLOW CALIBRATOR	[***]
K15	MERCURY ANALYZER - JEROME	[***]
K17	MERCURY ANALYZER - RA915 LUMEX	[***]
K20	AEROSOL MONITOR	[***]
K21	HEAT STRESS MONITOR	[***]
K45	LANDTECH METER	[***]
K46	GEM 5000 W/GPS	[***]
K50	PHOTOIONIZATION DETECTOR	[***]
K51	DOSIMETER	[***]
K54	LEL 4 GAS METER	[***]
K55	PASSIVE 4 GAS LEL METER	[***]
K60	4 GAS METER W/PID	[***]
K65	ORGANIC VAPOR ANALYZER	[***]
K67	OPTICAL EMISSION SPECTROMETER	[***]
K68	FID W/PID	[***]

K72	400K PSI TENSILE TESTER	[***]
K73	600K PSI TENSILE TESTER	[***]
L05	VACUUM TRUCK - 2000 GAL	[***]
L25	VACUUM UNIT-1500 GAL OSHA	[***]
M01	BARREL SHREDDER	[***]
M08	PUGMILL 100-200 TON/HR	[***]
M09	CEMENT SILO	[***]
N26	NUCLEAR PLATE SOURCE	[***]
N27	NUCLEAR BUTTON SOURCE	[***]
N28	NUCLEAR DISC SOURCE	[***]
N30	2-CHANNEL ALPHA/BETA W/PROBE	[***]
N35	1-CHANNEL SCALER/RATEMETER	[***]
N37	HDHLD AND BENCH FRISKER	[***]
N38	GAMMA SCINTILLATION SURVEYOR	[***]
N41	ALPHA/BETA SAMPLE COUNTER	[***]
N43	LOW VOL PUMPS 14-115 LPM	[***]
N44	LAB AUTO LO BKGRD ALPHA/BETA	[***]
N45	GAMA SPECTROMETER	[***]
N52	XRF TRI-SOURCE ANALYZER	[***]
O05	TRIPLE REEL CABLE TRAILER	[***]
O07	CABLE REEL TRAILER	[***]
O08	FUSION WELDER 412	[***]
O09	KUBOTA RTV1140, 4 SEATER	[***]
O10	KUBOTA RTV900	[***]
O11	SMALL ATV	[***]
O12	PULLER, ELEC WIRING, TRAILER MOUNTED	[***]
O13	CABLE ROLLER	[***]
O15	FUSION MACHINE 618	[***]
O16	FUSION MACHINE 28	[***]
O19	LIGHT PLANT	[***]
O20	MOBILE LIGHT TOWER, 27K WATT	[***]
O24	ROD ROOM	[***]
O25	CONCRETE PIPE PULLER	[***]
O27	40’ WELD TEST CONTAINER	[***]
O28	40 FOOT RESTROOM	[***]
O29	ORBITAL WELDING CONTAINERS	[***]
O30	6 ZONE HEAT STRESS RELIEF UNIT	[***]
O31	SPOT COOLERS	[***]
O32	12 ZONE HEAT STRESS RELIEF	[***]

O33	40' TIME KEEPING ALLEY	[***]
O35	10 TON GANTRY CRANE	[***]
O36	CONDUIT BENDER	[***]
O38	CONDUIT BENDER W/TABLE 2-4 INCH	[***]
O40	4" PVC SOCKET WELDER	[***]
O41	6-8" PIPE LIFTING BAR SET	[***]
O42	PORTABLE ROOF 40X40	[***]
O43	MODULAR CONTROL DUAL	[***]
O44	MODULAR CONTROL SINGLE	[***]
O45	PORTABLE ROOF 40X20	[***]
O47	12 ZONE HEAT STRESS W/DIGITAL RECORDER	[***]
O50	8 PACK LINCOLN V275 CC	[***]
O51	6-PAK WELDER	[***]
O52	4-PAK WELDER	[***]
O53	WELDER, 400-500 AMP CC/CV	[***]
O60	MAN RETRIEVEL SYSTEM	[***]
O71	415 POWER SUPPLY	[***]
O72	M227 POWER SUPPLY	[***]
O73	M15 WELD HEAD	[***]
O74	M52 WELD HEAD	[***]
O75	M81 WELD HEAD	[***]
O76	TORCH NGT W/OPTICS AND VIDEO	[***]
O78	2"-5" GUIDE RING	[***]
O79	8.625" GUIDE RING	[***]
O80	10.75" GUIDE RING	[***]
O81	12.75" GUIDE RING	[***]
O82	16" GUIDE RING	[***]
O83	20" GUIDE RING	[***]
O84	24" GUIDE RING	[***]
O85	28" GUIDE RING	[***]
O86	30" GUIDE RING	[***]
O87	36" GUIDE RING	[***]
O88	48" GUIDE RING	[***]
O90	14" GUIDE RING	[***]
O91	34" GUIDE RING	[***]
O92	M415-DV VISION SYS	[***]
O94	FIRE EXTINGUISHER TRAINING SYSTEM	[***]
O95	CONCRETE BUGGY	[***]
O96	52" GUIDE RING	[***]

O97	ADJ WELD HEAD FRONT-END	[***]
O98	12 ZONE HEAT STRESS W/REMOTE	[***]
P01	GROUT PUMP 5CY/HR VERSA PUMP	[***]
P56	4X3 HIGH PRESSURE PUMP	[***]
P60	STEAMER W/TRAILER	[***]
P72	TRASH PUMP - 6 IN	[***]
Q10	PICK-UP TRUCK - GUAM	[***]
Q19	DUMP TRUCK (3 CU YDS) - GUAM	[***]
Q61	WELDER, 400 AMP DIESEL - GUAM	[***]
Q62	AIR COMPRESSOR, 185 CFM	[***]
Q80	DECON/OFFICE TRAILER - GUAM	[***]
Q82	TOOL & STORAGE TRAILER - GUAM	[***]
S01	FREIGHT/PERSONNEL ELEVATOR	[***]
S16	TELESCOPIC BELT CONVEYOR	[***]
S20	PRIMARY BATCH PLANT	[***]
S21	SECONDARY BATCH PLANT	[***]
S23	VOGTLE - HLD125	[***]
S30	PIPE PREP MACHINE, 4-8”	[***]
S31	PIPE PREP MACHINE, 6-12”	[***]
S32	PIPE PREP MACHINE, 10-16”	[***]
S33	PIPE PREP MACHINE, 18-24”	[***]
S34	PIPE PREP MACHINE, 22-28”	[***]
S35	PIPE PREP MACHINE, 30-36”	[***]
S36	HYDRAULIC POWER UNIT	[***]
S37	COUNTERBORE MODULE, 4-20”	[***]
S38	COUNTERBORE MODULE, 24-28”	[***]
S39	COUNTERBORE MODULE, 28-36”	[***]
S40	PORTABLE END PREP MACHINE	[***]
S41	END PREP LATHE	[***]
S42	GMAW ROBOTIC WELD SYSTEM	[***]
S43	GTAW LEAK CHASE WELD SYSTEM	[***]
S44	70 FT. WELD TRACK SYSTEM	[***]
S45	POWER DRILL SYSTEM, MULTI-AXLE	[***]
S46	NEXT GEN WELD SYSTEM	[***]
S47	BACKING BAR HOLDING SYSTEM	[***]
S48	WELD COUPON CUTTER	[***]
S49	HYD WRAP AROUND BENDER	[***]
S50	RMTS GRINDER ATTACHMENT	[***]
S51	GROUT MIXER	[***]

S52	WELD COUPON STATION	[***]
S53	GTAW LEAK CHASE TORCH HEAD	[***]
T04	FIELD ANALYTICAL TRAILER	[***]
T08	DECON/OFFICE TRAILER 28’	[***]
T09	DECON/OFFICE TRAILER 45’	[***]
T10	SECURED PARTS STORAGE CONTAINER	[***]
T11	TOOL AND STORAGE TRLR, <24’	[***]
T13	TOOL AND STORAGE TRLR, 40’-48’	[***]
T14	DROP DECK TRAILER	[***]
T15	TRANSPORT TRAILER, 30-35 TON	[***]
T16	LOWBOY TRAILER	[***]
T21	FLATBED TRAILER, HIGH CAPACITY	[***]
T22	FLATBED TRAILER, LOW CAPACITY	[***]
T26	ICE TRAILER	[***]
T28	LUBE TRAILER	[***]
T29	5TH WHEEL DOLLY TRAILER	[***]
T30	48’-70’ EXP DROP DECK TRAILER	[***]
T31	POWER PACK FOR GOLDHOFER	[***]
T32	CONNEX GROUND LEVEL OFFICE 40’	[***]
T33	CONNEX GROUND LEVEL OFFICE 20’	[***]
T34	WELL DEVELOPMENT TRAILER	[***]
T35	MOBILE SHOP/PIPE TRAILER, 18’	[***]
T37	UXO DIVE TRAILER	[***]
T39	6 LINE TRAILER FOR GOLDHOFER	[***]
T40	UPENDER TRAILER	[***]
T41	CEMENT STORAGE TRAILER, 4100 CU FT	[***]
T42	WIRE ROPE SPOOLING TRAILER	[***]
T43	TAG TRAILER, 20 TON	[***]
T44	POWER PACK, 210HP FOR GOLDHOFER	[***]
U77	DIGITAL REPEATER	[***]
U78	REPEATER STATION	[***]
U79	HAND-HELD RADIO 10 PACK	[***]
U80	HAND-HELD RADIO	[***]
U82	REMOTE FIRING DEVICE	[***]
V02	OVER-THE-ROAD DISL TRCTR	[***]
V04	TRUCK - ONE TON STAKE	[***]
V05	TRUCK - TWO TON STAKE	[***]
V06	DUMP TRUCK (5-10 CU YDS)	[***]
V07	DUMP TRUCK (11-15 CU YDS)	[***]

V08	HYDRO EXCAVATOR, TRUCK MOUNTED	[***]
V11	COMPACT PICK-UP TRUCK	[***]
V12	PICK-UP TRUCK	[***]
V13	PICK-UP - 4WD	[***]
V15	SPORT UTILITY VEHICLE	[***]
V16	WATER TRUCK, 1500-2000 GAL	[***]
V17	WATER TRUCK, 3000-4000 GAL	[***]
V18	CARGO VAN	[***]
V19	VAN	[***]
V21	FUEL TRUCK	[***]
V22	TRUCK FUEL/LUBE	[***]
V23	UTILITY TRUCK	[***]
V24	AIR QUALITY VEHICLE	[***]
V26	ETA - AMBULANCE	[***]
V32	PICK-UP TRUCK, CREW CAB 4X2	[***]
V33	PICK-UP TRUCK, CREW CAB 4X4	[***]
V34	STEP VAN	[***]
V35	SERVICE BODY TRUCK	[***]
V36	PROJECT MAINTENANCE TRUCK	[***]
V37	CRANE MAINTENANCE TRUCK	[***]
V49	TANDEM AXLE FLATBED TRUCK	[***]
V50	TANDEM AXLE YARD TRUCK	[***]
V52	ONE-TON DIESEL DUALY	[***]
V53	47 METER BOOM TRUCK PUMP	[***]
V54	61 METER BOOM TRUCK PUMP	[***]
V55	CONCRETE MIXER TRUCK	[***]
V56	63 METER BOOM TRUCK PUMP	[***]
V57	70 METER BOOM TRUCK PUMP	[***]
V60	SNOW PLOW TRUCK, 4X4	[***]
W15	DEWATERING PRESS - BASF	[***]
W16	PQ EXCELL ICPMS SYSTEM - QATS	[***]
W17	ICA 61-E SPECTOMETER - QATS	[***]
W18	TEKMAR - QATS	[***]
W24	EXPLOSION PROOF REFRIGERATOR - QATS	[***]
W26	PWC STANDARD PANEL VAN	[***]
W27	PWC 1 1/2 TON STAKE BED TRUCK	[***]
W28	PWC 3/4 TON PICKUP TRUCK	[***]
W29	PWC 1/2 TON PICKUP TRUCK	[***]
W30	PWC 1/4 TON PICKUP TRUCK	[***]

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W31	PWC 1 TON HD UTILITY BODY TRUCK	[***]
W32	PWC FORKLIFT	[***]
X30	JON BOAT	[***]
X56	COMMAND TRAILER	[***]
Y05	DRILL RIG - AF6	[***]
Y10	FUSION WELDING TRAILER - SOLID WASTE	[***]
Y18	PICK-UP - 4WD - SOLID WASTE	[***]
Y22	UTILITY TRUCK - SOLID WASTE	[***]
Y23	COMPACT PICK-UP TRUCK 4WD - SW	[***]
Y31	LANDTEC METER GEM 500 - SOLID WASTE	[***]
Y36	TOOL & STORAGE TRAILER >50’	[***]
Y56	824 FUSION WELDER W/GEN & TRLR	[***]
Y57	12/36 FUSION MACHINE	[***]
Y58	2-8” FUSION WELDER	[***]
Y59	6-18” FUSION WELDER	[***]

EXHIBIT J-1

DAVIS-BACON ACT REQUIRED PROVISIONS

ARTICLE 34. SECTION (a) MINIMUM WAGES, ETC.

(1) Minimum wages.

(i) All laborers and mechanics employed or working upon the site of the work (or under the United States Housing Act of 1937 or under the Housing Act of 1949 in the construction or development of the project), will be paid unconditionally and not less often than once a week, and without subsequent deduction or rebate on any account (except such payroll deductions as are permitted by regulations issued by the Secretary of Labor under the Copeland Act (29 CFR part 3)), the full amount of wages and bona fide fringe benefits (or cash equivalents thereof) due at time of payment computed at rates not less than those contained in the wage determination of the Secretary of Labor which is attached hereto and made a part hereof, regardless of any contractual relationship which may be alleged to exist between the contractor and such laborers and mechanics.

Contributions made or costs reasonably anticipated for bona fide fringe benefits under section 1 (b)(2) of the Davis-Bacon Act on behalf of laborers or mechanics are considered wages paid to such laborers or mechanics, subject to the provisions of paragraph (a)(l)(iv) of this section; also, regular contributions made or costs incurred for more than a weekly period (but not less often than quarterly) under plans, funds, or programs which cover the particular weekly period, are deemed to be constructively made or incurred during such weekly period. Such laborers and mechanics shall be paid the appropriate wage rate and fringe benefits on the wage determination for the classification of work actually performed, without regard to skill, except as provided in Sec. 5.5(a)(4) [paragraph (a)(4) below]. Laborers or mechanics performing work in more than one classification may be compensated at the rate specified for each classification for the time actually worked therein: Provided, That the employer's payroll records accurately set forth the time spent in each classification in which work is performed. The wage determination (including any additional classification and wage rates conformed under paragraph (a)(l)(ii) of this section) and the Davis-Bacon poster (WH-1321) shall be posted at all times by the contractor and its subcontractors at the site of the work in a prominent and accessible place where it can be easily seen by the workers.

(ii)(A) The contracting officer shall require that any class of laborers or mechanics, including helpers, which is not listed in the wage determination and which is to be employed under the contract shall be classified in conformance with the wage determination. The contracting officer shall approve an additional classification and wage rate and fringe benefits therefore only when the following criteria have been met:

(1) The work to be performed by the classification requested is not performed by a classification in the wage determination; and

(2) The classification is utilized in the area by the construction industry; and

(3) The proposed wage rate, including any bona fide fringe benefits, bears a reasonable relationship to the wage rates contained in the wage determination.

(ii)(B) If the contractor and the laborers and mechanics to be employed in the classification (if known), or their representatives, and the contracting officer agree on the classification and wage rate (including the amount designated for fringe benefits where appropriate), a report of the action taken shall be sent by the contracting officer to the Administrator of the Wage and Hour Division, Employment Standards Administration, U.S. Department of Labor, Washington, DC 20210. The Administrator, or an authorized representative, will approve, modify, or disapprove every additional classification action within 30 days of receipt and so advise the contracting officer or will notify the contracting officer within the 30-day period that additional time is necessary.

(ii)(C) In the event the contractor, the laborers or mechanics to be employed in the classification or their representatives, and the contracting officer do not agree on the proposed classification and wage rate (including the amount designated for fringe benefits, where appropriate), the contracting officer shall refer the questions, including the views of all interested parties and the recommendation of the contracting officer, to the Administrator for determination. The Administrator, or an authorized representative, will issue a determination within 30 days of receipt and so advise the contracting officer or will notify the contracting officer within the 30-day period that additional time is necessary.

(ii)(D) The wage rate (including fringe benefits where appropriate) determined pursuant to paragraphs (a)(1)(ii) (B) or (C) of this section, shall be paid to all workers performing work in the classification under this contract from the first day on which work is performed in the classification.

(iii) Whenever the minimum wage rate prescribed in the contract for a class of laborers or mechanics includes a fringe benefit which is not expressed as an hourly rate, the contractor shall either pay the benefit as stated in the wage determination or shall pay another bona fide fringe benefit or an hourly cash equivalent thereof.

(iv) If the contractor does not make payments to a trustee or other third person, the contractor may consider as part of the wages of any laborer or mechanic the amount of any costs reasonably anticipated in providing bona fide fringe benefits under a plan or program, Provided, That the Secretary of Labor has found, upon the written request of the contractor, that the applicable standards of the Davis-Bacon Act have been met. The Secretary of Labor may require the contractor to set aside in a separate account assets for the meeting of obligations under the plan or program.

(2) Withholding.

The Department of Energy (“DOE”) shall upon its own action or upon written request of an authorized representative of the Department of Labor withhold or cause to be withheld

from the contractor under this contract or any other Federal contract with the same prime contractor, or any other federally-assisted contract subject to Davis-Bacon prevailing wage requirements, which is held by the same prime contractor, so much of the accrued payments or advances as may be considered necessary to pay laborers and mechanics, including apprentices, trainees, and helpers, employed by the contractor or any subcontractor the full amount of wages required by the contract. In the event of failure to pay any laborer or mechanic, including any apprentice, trainee, or helper, employed or working on the site of the work (or under the United States Housing Act of 1937 or under the Housing Act of 1949 in the construction or development of the project), all or part of the wages required by the contract, DOE may, after written notice to the contractor, sponsor, applicant, or owner, take such action as may be necessary to cause the suspension of any further payment, advance, or guarantee of funds until such violations have ceased.

(3) Payrolls and basic records.

(i) Payrolls and basic records relating thereto shall be maintained by the contractor during the course of the work and preserved for a period of three years thereafter for all laborers and mechanics working at the site of the work (or under the United States Housing Act of 1937, or under the Housing Act of 1949, in the construction or development of the project). Such records shall contain the name, address, and social security number of each such worker, his or her correct classification, hourly rates of wages paid (including rates of contributions or costs anticipated for bona fide fringe benefits or cash equivalents thereof of the types described in section 1(b)(2)(B) of the Davis-Bacon Act), daily and weekly number of hours worked, deductions made and actual wages paid. Whenever the Secretary of Labor has found under 29 CFR 5.5(a)(1)(iv) that the wages of any laborer or mechanic include the amount of any costs reasonably anticipated in providing benefits under a plan or program described in section 1(b)(2)(B) of the Davis-Bacon Act, the contractor shall maintain records which show that the commitment to provide such benefits is enforceable, that the plan or program is financially responsible, and that the plan or program has been communicated in writing to the laborers or mechanics affected, and records which show the costs anticipated or the actual cost incurred in providing such benefits. Contractors employing apprentices or trainees under approved programs shall maintain written evidence of the registration of apprenticeship programs and certification of trainee programs, the registration of the apprentices and trainees, and the ratios and wage rates prescribed in the applicable programs.

(ii)(A) The contractor shall submit weekly for each week in which any contract work is performed a copy of all payrolls to the DOE) if the agency is a party to the contract, but if the agency is not such a party, the contractor will submit the payrolls to the applicant, sponsor, or owner, as the case may be, for transmission to DOE. The payrolls submitted shall set out accurately and completely all of the information required to be maintained under 29 CFR 5.5(a)(3)(i), except that full social security numbers and home addresses shall not be included on weekly transmittals. Instead the payrolls shall only need to include an individually identifying number for each employee (e.g., the last four digits of

the employee's social security number). The required weekly payroll information may be submitted in any form desired. Optional Form WH-347 is available for this purpose from the Wage and Hour Division Web site at http://www.dol.gov/esa/whd/forms/wh347instr.htm or its successor site. The prime contractor is responsible for the submission of copies of payrolls by all subcontractors. Contractors and subcontractors shall maintain the full social security number and current address of each covered worker, and shall provide them upon request to DOE if the agency is a party to the contract, but if the agency is not such a party, the contractor will submit them to the applicant, sponsor, or owner, as the case may be, for transmission to DOE, the contractor, or the Wage and Hour Division of the Department of Labor for purposes of an investigation or audit of compliance with prevailing wage requirements. It is not a violation of this section for a prime contractor to require a subcontractor to provide addresses and social security numbers to the prime contractor for its own records, without weekly submission to the sponsoring government agency (or the applicant, sponsor, or owner).

(ii)(B) Each payroll submitted shall be accompanied by a "Statement of Compliance," signed by the contractor or subcontractor or his or her agent who pays or supervises the payment of the persons employed under the contract and shall certify the following:

(1) That the payroll for the payroll period contains the information required to be provided under Sec. 5.5 (a)(3)(ii) of Regulations, 29 CFR part 5, the appropriate information is being maintained under Sec. 5.5 (a)(3)(i) of Regulations, 29 CFR part 5, and that such information is correct and complete;

(2) That each laborer or mechanic (including each helper, apprentice, and trainee) employed on the contract during the payroll period has been paid the full weekly wages earned, without rebate, either directly or indirectly, and that no deductions have been made either directly or indirectly from the full wages earned, other than permissible deductions as set forth in Regulations, 29 CFR part 3;

(3) That each laborer or mechanic has been paid not less than the applicable wage rates and fringe benefits or cash equivalents for the classification of work performed, as specified in the applicable wage determination incorporated into the contract.

(ii)(C) The weekly submission of a properly executed certification set forth on the reverse side of Optional Form WH-347 shall satisfy the requirement for submission of the "Statement of Compliance" required by paragraph (a)(3)(ii)(B) of this section.

(ii)(D) The falsification of any of the above certifications may subject the contractor or subcontractor to civil or criminal prosecution under section 1001 of title 18 and section 231 of title 31 of the United States Code.

(iii) The contractor or subcontractor shall make the records required under paragraph (a)(3)(i) of this section available for inspection, copying, or transcription by authorized representatives of DOE or the Department of Labor, and shall permit such representatives

to interview employees during working hours on the job. If the contractor or subcontractor fails to submit the required records or to make them available, the Federal agency may, after written notice to the contractor, sponsor, applicant, or owner, take such action as may be necessary to cause the suspension of any further payment, advance, or guarantee of funds. Furthermore, failure to submit the required records upon request or to make such records available may be grounds for debarment action pursuant to 29 CFR 5.12.

(4) Apprentices and trainees

(i) Apprentices. Apprentices will be permitted to work at less than the predetermined rate for the work they performed when they are employed pursuant to and individually registered in a bona fide apprenticeship program registered with the U.S. Department of Labor, Employment and Training Administration, Office of Apprenticeship Training, Employer and Labor Services, or with a State Apprenticeship Agency recognized by the Office, or if a person is employed in his or her first 90 days of probationary employment as an apprentice in such an apprenticeship program, who is not individually registered in the program, but who has been certified by the Office of Apprenticeship Training, Employer and Labor Services or a State Apprenticeship Agency (where appropriate) to be eligible for probationary employment as an apprentice. The allowable ratio of apprentices to journeymen on the job site in any craft classification shall not be greater than the ratio permitted to the contractor as to the entire work force under the registered program. Any worker listed on a payroll at an apprentice wage rate, who is not registered or otherwise employed as stated above, shall be paid not less than the applicable wage rate on the wage determination for the classification of work actually performed. In addition, any apprentice performing work on the job site in excess of the ratio permitted under the registered program shall be paid not less than the applicable wage rate on the wage determination for the work actually performed. Where a contractor is performing construction on a project in a locality other than that in which its program is registered, the ratios and wage rates (expressed in percentages of the journeyman's hourly rate) specified in the contractor's or subcontractor's registered program shall be observed. Every apprentice must be paid at not less than the rate specified in the registered program for the apprentice's level of progress, expressed as a percentage of the journeymen hourly rate specified in the applicable wage determination. Apprentices shall be paid fringe benefits in accordance with the provisions of the apprenticeship program. If the apprenticeship program does not specify fringe benefits, apprentices must be paid the full amount of fringe benefits listed on the wage determination for the applicable classification. If the Administrator determines that a different practice prevails for the applicable apprentice classification, fringes shall be paid in accordance with that determination. In the event the Office of Apprenticeship Training, Employer and Labor Services, or a State Apprenticeship Agency recognized by the Office, withdraws approval of an apprenticeship program, the contractor will no longer be permitted to utilize apprentices at less than the applicable predetermined rate for the work performed until an acceptable program is approved.

(ii) Trainees. Except as provided in 29 CFR 5.16, trainees will not be permitted to work at less than the predetermined rate for the work performed unless they are employed pursuant to and individually registered in a program which has received prior approval, evidenced by formal certification by the U.S. Department of Labor, Employment and Training Administration. The ratio of trainees to journeymen on the job site shall not be greater than permitted under the plan approved by the Employment and Training Administration. Every trainee must be paid at not less than the rate specified in the approved program for the trainee's level of progress, expressed as a percentage of the journeyman hourly rate specified in the applicable wage determination. Trainees shall be paid fringe benefits in accordance with the provisions of the trainee program. If the trainee program does not mention fringe benefits, trainees shall be paid the full amount of fringe benefits listed on the wage determination unless the Administrator of the Wage and Hour Division determines that there is an apprenticeship program associated with the corresponding journeyman wage rate on the wage determination which provides for less than full fringe benefits for apprentices. Any employee listed on the payroll at a trainee rate who is not registered and participating in a training plan approved by the Employment and Training Administration shall be paid not less than the applicable wage rate on the wage determination for the classification of work actually performed. In addition, any trainee performing work on the job site in excess of the ratio permitted under the registered program shall be paid not less than the applicable wage rate on the wage determination for the work actually performed. In the event the Employment and Training Administration withdraws approval of a training program, the contractor will no longer be permitted to utilize trainees at less than the applicable predetermined rate for the work performed until an acceptable program is approved.

(iii) Equal employment opportunity. The utilization of apprentices, trainees and journeymen under this part shall be in conformity with the equal employment opportunity requirements of Executive Order 11246, as amended, and 29 CFR part 30.

(5) Compliance with Copeland Act requirements.

The contractor shall comply with the requirements of 29 CFR part 3, which are incorporated by reference in this contract.

(6) Subcontracts.

The contractor or subcontractor shall insert in any subcontracts the clauses contained in 29 CFR 5.5(a)(1) through (10) and such other clauses as DOE may by appropriate instructions require, and also a clause requiring the subcontractors to include these clauses in any lower tier subcontracts. The prime contractor shall be responsible for the compliance by any subcontractor or lower tier subcontractor with all the contract clauses in 29 CFR 5.5.

(7) Contract termination: debarment.

A breach of the contract clauses in 29 CFR 5.5 may be grounds for termination of the contract, and for debarment as a contractor and a subcontractor as provided in 29 CFR 5.12.

(8) Compliance with Davis-Bacon and Related Acts requirements.

All rulings and interpretations of the Davis-Bacon and Related Acts contained in 29 CFR parts 1, 3, and 5 are herein incorporated by reference in this contract.

(9) Disputes concerning labor standards.

Disputes arising out of the labor standards provisions of this contract shall not be subject to the general disputes clause of this contract. Such disputes shall be resolved in accordance with the procedures of the Department of Labor set forth in 29 CFR parts 5, 6, and 7. Disputes within the meaning of this clause include disputes between the contractor (or any of its subcontractors) and the contracting agency, the U.S. Department of Labor, or the employees or their representatives.

(10) Certification of eligibility.

(i) By entering into this contract, the contractor certifies that neither it (nor he or she) nor any person or firm who has an interest in the contractor's firm is a person or firm ineligible to be awarded Government contracts by virtue of section 3(a) of the Davis-Bacon Act or 29 CFR 5.12(a)(1).

(ii) No part of this contract shall be subcontracted to any person or firm ineligible for award of a Government contract by virtue of section 3(a) of the Davis-Bacon Act or 29 CFR 5.12(a)(1).

(iii) The penalty for making false statements is prescribed in the U.S. Criminal Code, 18 U.S.C. 1001.

EXHIBIT J-2

DAVIS-BACON ACT WAGE DETERMINATION(S)

1. For all construction (as defined in DOL regulations at 29 CFR 5.2 to include installation where appropriate, hereinafter "construction") under this Agreement and subcontracts hereunder, incorporate the following "Heavy" wage determination schedule and conformances: GA90 Modification 0 (1/03/14), found at: http://www.wdol.gov/wdol/scafiles/davisbacon/GA90.dvb, and attached hereto as Exhibit J-3 .

2. For all construction under this Agreement and subcontracts hereunder, on sheltered enclosures with walk-in access for the purpose of housing persons, machinery, equipment, incorporate the following "Building" wage determination schedule: GA126 Modification 1 (1/17/14) found at http://www.wdol.gov/wdol/scafiles/davisbacon/GA126.dvb, and attached hereto as Exhibit J-4 .

3. For all construction under this Agreement and subcontracts hereunder, on paved roads and other paved surfaces, please use GA7 Modification 0 (1/3/14) "Highway" schedule found at http://www.wdol.gov/wdol/scafiles/davisbacon/GA7.dvb, and attached hereto as Exhibit J-5 .

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EXHIBIT J-3

HEAVY WAGE DETERMINATION

General Decision Number: GA140090 01/03/2014 GA90

Superseded General Decision Number: GA20130090

State: Georgia

Construction Type: Heavy
Heavy Construction, Includes Water and Sewer Lines, and Heavy Construction on Treatment Plant Sites and Industrial Sites (Refineries, Power Plants, Chemical and Manufacturing Plants, Paper Mills, Etc.)

Counties: Burke, McDuffie and Richmond Counties in Georgia.

Modification Number	Publication Date
0	01/03/2014

* ELEC1579-002 10/01/2013

	Rates	Fringes
ELECTRICIAN	$ 23.00	11.40

ENGI0474-029 07/01/2013

BURKE & RICHMOND COUNTIES

	Rates	Fringes
POWER EQUIPMENT OPERATOR:		
Crane: 119 Tons and Under	$ 24.55	12.30
Crane: 120 to 249 Tons	$ 25.55	12.30
Crane: 250 to 499 Tons	$ 26.55	12.30
Crane: 500 Tons and Larger	$ 27.55	12.30
Mechanic	$ 24.55	12.30

ENGI0926-032 07/01/2013

MCDUFFIE COUNTY

	Rates	Fringes
POWER EQUIPMENT OPERATOR:		
Crane, Mechanic	$ 27.88	10.13

SUGA2012-108 08/11/2012

	Rates	Fringes
CARPENTER (Form Work Only)	$ 15.44	0.00
CARPENTER, Excludes Form Work	$ 14.76	0.00
CEMENT MASON/CONCRETE FINISHER	$ 16.96	0.00
IRONWORKER, REINFORCING	$ 13.30	1.66
LABORER: Common or General	$ 9.84	0.00
LABORER: Pipelayer	$ 9.48	0.00
OPERATOR: Backhoe/Excavator/Trackhoe	$ 12.80	0.00
OPERATOR: Bulldozer	$ 14.58	0.00
OPERATOR: Grader/Blade	$ 20.24	0.00
OPERATOR: Loader	$ 16.59	4.13
OPERATOR: Piledriver	$ 18.72	2.06
OPERATOR: Roller	$ 12.04	0.69
TRUCK DRIVER: Dump Truck	$ 12.79	0.00
TRUCK DRIVER: Lowboy Truck	$ 17.28	1.84

WELDERS - Receive rate prescribed for craft performing operation to which welding is incidental.

Unlisted classifications needed for work not included within the scope of the classifications listed may be added after award only as provided in the labor standards contract clauses (29CFR 5.5 (a) (1) (ii)).

The body of each wage determination lists the classification and wage rates that have been found to be prevailing for the cited type(s) of construction in the area covered by the wage determination. The classifications are listed in alphabetical order of “identifiers” that indicate whether the particular rate is union or non-union.

Union Identifiers

An identifier enclosed in dotted lines beginning with characters other than “SU” denotes that the union classification and rate have found to be prevailing for that classification. Example: PLUM0198-005 07/01/2011. The first four letters , PLUM, indicate the international union and the four-digit number, 0198, that follows indicates the local union number or district council number where applicable , i.e., Plumbers Local 0198. The next number, 005 in the example, is an internal number used in processing the wage determination. The date, 07/01/2011, following these characters is the effective date of the most current negotiated rate/collective bargaining agreement which would be July 1, 2011 in the above example.

Union prevailing wage rates will be updated to reflect any changes in the collective bargaining agreements governing the rates.

0000/9999: weighted union wage rates will be published annually each January.

Non-Union Identifiers

Classifications listed under an “SU” identifier were derived from survey data by computing average rates and are not union rates; however, the data used in computing these rates may include both union and non-union data. Example: SULA2004-007 5/13/2010. SU indicates the rates are not union majority rates, LA indicates the State of Louisiana; 2004 is the year of the survey; and 007 is an internal number used in producing the wage determination. A 1993 or later date, 5/13/2010, indicates the classifications and rates under that identifier were issued as a General Wage Determination on that date.

Survey wage rates will remain in effect and will not change until a new survey is conducted.

WAGE DETERMINATION APPEALS PROCESS

1.) Has there been an initial decision in the matter? This can be:

an existing published wage determination

a survey underlying a wage determination

a Wage and Hour Division letter setting forth a position on a wage determination matter

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a conformance (additional classification and rate) ruling

On survey related matters, initial contact, including requests for summaries of surveys, should be with the Wage and Hour Regional Office for the area in which the survey was conducted because those Regional Offices have responsibility for the Davis-Bacon survey program. If the response from this initial contact is not satisfactory, then the process described in 2.) and 3.) should be followed.

With regard to any other matter not yet ripe for the formal process described here, initial contact should be with the Branch of Construction Wage Determinations. Write to:

Branch of Construction Wage Determinations
Wage and Hour Division
U.S. Department of Labor
200 Constitution Avenue, N.W.
Washington, DC 20210

2.) If the answer to the question in 1.) is yes, then an interested party (those affected by the action) can request review and reconsideration from the Wage and Hour Administrator (See 29 CFR Part 1.8 and 29 CFR Part 7). Write to:

Wage and Hour Administrator
U.S. Department of Labor
200 Constitution Avenue, N.W.
Washington, DC 20210

The request should be accompanied by a full statement of the interested party's position and by any information (wage payment data, project description, area practice material, etc.) that the requestor considers relevant to the issue.

3.) If the decision of the Administrator is not favorable, an interested party may appeal directly to the Administrative Review Board (formerly the Wage Appeals Board). Write to:

Administrative Review Board
U.S. Department of Labor
200 Constitution Avenue, N.W.
Washington, DC 20210

4.) All decisions by the Administrative Review Board are final.

END OF GENERAL DECISION

Exhibit J-3

U.S. Department of Labor

Wage and Hour Division
Washington, D.C. 20210

JUN 2 2014

Ms. Nikky Ude
Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585
Nikky.Ude@hq.doe.gov

RE: Project No.: Units 3 and 4 of Vogtle Electric Plant
Wage Decision No.: GA140090 Mod. 0
Location: Burke County, GA
WHD Number: 4790

Dear Ms. Ude:

This is in response to your request proposing the additional classifications and wage rates to the above wage decision in accordance with 29 CFR 5.5(a)(1)(ii).

PROPOSED CLASSIFCATIONS	PROPOSED HOURLY RATE	FRINGE BENEFITS
Asbestos Worker/Insulator	$23.92	$12.04
Millwright	$26.95	$11.55
Sprinkler Fitter	$25.99	$15.87
Mechanic Services	$18.21	$12.35
Machinist	$26.95	$11.55
Well Driller	$24.55	$12.35

The request for Mechanic Services is not approved because the work to be performed by this classification may be performed by a classification already included in the wage decision [see 29 C.F.R., section 5.5(a)(1)(ii)(A)(1)]. The appropriate classification is Mechanic at a rate of $24.55 per hour plus $12.30 in fringe benefits and shall be paid to all workers performing work in the classification under this contract from the first day on which work is performed.

The Machinist is not subject as the Davis-Bacon Act provides that prevailing wages are to be paid to all mechanics and laborers employed directly upon the site of work. The regulations [see 29 C.F.R., section 5.2(1)] define the site of work as limited to the physical place or places where the construction called for in the contract will remain when work on it is completed and other adjacent or nearby property used in the construction.

The remaining classifications and wage rates are approved and the wage rates proposed must be paid to all workers performing work within the classifications under this contract from the first day work is performed.

Your request has been conformed consistent with All Agency Memorandum 213 (http://www.wdol.gov/aam/aam213.pdf) which describes the conformance process in detail and the basis on which your proposed rate was denied. Any requests for appeal of the conformance decision must be made within thirty (30) days from the date of this letter. If you have any questions or concerns regarding this conformance decision, please contact the undersigned at the telephone or email address listed below.

Sincerely,

/s/ T. Holmes for

Kenneth Reinshuttle
Section Chief
Davis Bacon Branch
Wage & Hour Division
202.693.1016
reinshuttle.ken@dol.gov

EXHIBIT J-4

BUILDING WAGE DETERMINATION

General Decision Number: GA140126 01/17/2014 GA126

Superseded General Decision Number: GA20130126

State: Georgia

Construction Type: Building

County: Burke County in Georgia.

Modification Number	Publication Date
0	01/03/2014
1	01/17/2014

BOIL0026-001 01/01/2013

	Rates	Fringes
BOILERMAKER	$ 24.91	19.69

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* ELEV0032-001 01/01/2014

	Rates	Fringes
ELEVATOR MECHANIC	$ 36.96	26.785+a+b

PAID HOLIDAYS:

- a. New Year’s Day, Memorial Day, Independence Day, Labor Day, Vetern’s Day, Thanksgiving Day, the Friday after Thanksgiving, and Christmas Day.
- b. Employer contributes 8% of regular hourly rate to vacation pay credit for employee who has worked in business more than 5 years; 6% for less than 5 years’ service.

ENGI0474-003 07/01/2013

CONFIDENTIAL& PROPRIETARY
CONFIDENTIAL TRADE SECRET INFORMATION

POWER EQUIPMENT OPERATOR:		Rates	Fringes
Backhoe/Excavator, Bobcat/Skid Steer/Skid Loader, Bulldozer, Forklift (under 15 tons), and Loader	$	22.72	12.30
Crane (over 10 tons) and Forklift (15 tons and over)	$	24.55	12.30
Crane (over 120 tons)	$	25.55	12.30
Crane (over 250 tons)	$	26.55	12.30
Oiler	$	20.38	12.30

PLUM0150-006 10/01/2012

		Rates	Fringes
PLUMBER/PIPEFITTER	$	22.94	12.71

SHEE0085-003 08/01/2012

		Rates	Fringes
SHEET METAL WORKER (Including HVAC Duct Installation; Excluding Metal Roof Installation)	$	28.34	11.55

SUGA2012-033 08/11/2012

		Rates	Fringes
BRICKLAYER	$	16.00	0.00
CARPENTER, Includes Drywall Hanging and Metal Stud Installation	$	15.28	0.00
CEMENT MASON/CONCRETE FINISHER	$	16.58	0.00
DRYWALL FINISHER/TAPER	$	17.00	0.00
ELECTRICIAN	$	19.71	3.60
HVAC MECHANIC (Installation of HVAC Unit Only, Excludes Installation of HVAC Pipe and Duct)	$	18.00	3.89
IRONWORKER, REINFORCING	$	17.94	0.00
IRONWORKER, STRUCTURAL	$	20.00	0.35
LABORER: Common or General	$	10.25	0.32
LABORER: Mason Tender – Brick	$	9.00	0.00
LABORER: Pipelayer	$	12.00	0.23

	Rates	Fringes
OPERATOR: Grader/Blade	$ 17.52	0.00
PAINTER: Brush, Roller and Spray	$ 16.00	1.62
ROOFER (Installation of Metal Roofs Only)	$ 15.02	0.00
ROOFER, Excludes Installation of Metal Roofs	$ 10.76	0.00
TILE FINISHER	$ 10.31	0.00
TILE SETTER	$ 19.50	0.00
TRUCK DRIVER: Dump Truck	$ 12.70	0.00
TRUCK DRIVER: Lowboy Truck	$ 17.41	0.00

WELDERS - Receive rate prescribed for craft performing operation to which welding is incidental.

Unlisted classifications needed for work not included within the scope of the classifications listed may be added after award only as provided in the labor standards contract clauses (29CFR 5.5 (a) (1) (ii)).

The body of each wage determination lists the classification and wage rates that have been found to be prevailing for the cited type(s) of construction in the area covered by the wage determination. The classifications are listed in alphabetical order of “identifiers” that indicate whether the particular rate is union or non-union.

Union Identifiers

An identifier enclosed in dotted lines beginning with characters other than “SU” denotes that the union classification and rate have found to be prevailing for that classification. Example: PLUM0198-005 07/01/2011. The first four letters , PLUM, indicate the international union and the four-digit number, 0198, that follows indicates the local union number or district council number where applicable , i.e., Plumbers Local 0198. The next number, 005 in the example, is an internal number used in processing the wage determination. The date, 07/01/2011, following these characters is the effective date of the most current negotiated rate/collective bargaining agreement which would be July 1, 2011 in the above example.

Union prevailing wage rates will be updated to reflect any changes in the collective bargaining agreements governing the rates.

0000/9999: weighted union wage rates will be published annually each January.

Non-Union Identifiers

Classifications listed under an “SU” identifier were derived from survey data by computing average rates and are not union rates; however, the data used in computing these rates may include both union and non-union data. Example: SULA2004-007 5/13/2010. SU indicates the rates are not union majority rates, LA indicates the State of Louisiana; 2004 is the year of the survey; and 007 is an internal number used in producing the wage determination. A 1993 or later date, 5/13/2010, indicates the classifications and rates under that identifier were issued as a General Wage Determination on that date.

Survey wage rates will remain in effect and will not change until a new survey is conducted.

WAGE DETERMINATION APPEALS PROCESS

1.) Has there been an initial decision in the matter? This can be:

an existing published wage determination

a survey underlying a wage determination

a Wage and Hour Division letter setting forth a position on a wage determination matter

a conformance (additional classification and rate) ruling

On survey related matters, initial contact, including requests for summaries of surveys, should be with the Wage and Hour Regional Office for the area in which the survey was conducted because those Regional Offices have responsibility for the Davis-Bacon survey program. If the response from this initial contact is not satisfactory, then the process described in 2.) and 3.) should be followed.

With regard to any other matter not yet ripe for the formal process described here, initial contact should be with the Branch of Construction Wage Determinations. Write to:

Branch of Construction Wage Determinations
Wage and Hour Division
U.S. Department of Labor
200 Constitution Avenue, N.W.
Washington, DC 20210

2.) If the answer to the question in 1.) is yes, then an interested party (those affected by the action) can request review and reconsideration from the Wage and Hour Administrator (See 29 CFR Part 1.8 and 29 CFR Part 7). Write to:

Wage and Hour Administrator
U.S. Department of Labor
200 Constitution Avenue, N.W.
Washington, DC 20210

The request should be accompanied by a full statement of the interested party's position and by any information (wage payment data, project description, area practice material, etc.) that the requestor considers relevant to the issue.

3.) If the decision of the Administrator is not favorable, an interested party may appeal directly to the Administrative Review Board (formerly the Wage Appeals Board). Write to:

Administrative Review Board
U.S. Department of Labor
200 Constitution Avenue, N.W.
Washington, DC 20210

4.) All decisions by the Administrative Review Board are final.

END OF GENERAL DECISION

EXHIBIT J-5

HIGHWAY WAGE DETERMINATION

General Decision Number: GA140007 01/03/2014 GA7

Superseded General Decision Number: GA20130007

State: Georgia

Construction Type: Highway

Counties: Burke, Columbia, Glascock, Hancock, Jefferson, Jenkins, Lincoln, McDuffie, Richmond, Taliaferro, Warren, Washington and Wilkes Counties in Georgia.

HIGHWAY CONSTRUCTION PROJECTS

Modification Number	Publication Date
0	01/03/2014

SUGA2011-007 03/07/2011

	Rates	Fringes
CARPENTER	$ 11.45	
CEMENT MASON/CONCRETE FINISHER	$ 11.36	
LABORER		
Asphalt Raker	$ 11.00	
Asphalt Screed Person	$ 10.50	
Common or General	$ 8.93	
Form Setter	$ 10.35	
Guardrail Erector	$ 13.50	
Milling Machine Ground Person	$ 10.00	
Pipe Layer	$ 10.20	
POWER EQUIPMENT OPERATOR:		
Asphalt Distributor	$ 14.10	
Asphalt Paver/Spreader	$ 12.00	
Backhoe/Excavator	$ 10.80	
Bulldozer	$ 11.60	
Compactor	$ 10.00	
Crane/Dragline	$ 17.50	
Front End Loader	$ 10.70	
Material Transfer Vehicle (Shuttle Buggy)	$ 11.30	

	Rates	Fringes
Mechanic	$ 12.75	
Milling Machine	$ 11.50	
Motorgrader Fine Grade	$ 14.55	
Motorgrader/Blade	$ 16.00	
Roller	$ 10.00	
Water Truck	$ 11.25	
TRUCK DRIVER		
26,000 GVW & Under	$ 10.79	
26,001 GVW & Over	$ 12.75	

WELDERS - Receive rate prescribed for craft performing operation to which welding is incidental.

Unlisted classifications needed for work not included within the scope of the classifications listed may be added after award only as provided in the labor standards contract clauses (29CFR 5.5 (a) (1) (ii)).

The body of each wage determination lists the classification and wage rates that have been found to be prevailing for the cited type(s) of construction in the area covered by the wage determination. The classifications are listed in alphabetical order of “identifiers” that indicate whether the particular rate is union or non-union.

Union Identifiers

An identifier enclosed in dotted lines beginning with characters other than “SU” denotes that the union classification and rate have found to be prevailing for that classification. Example: PLUM0198-005 07/01/2011. The first four letters , PLUM, indicate the international union and the four-digit number, 0198, that follows indicates the local union number or district council number where applicable , i.e., Plumbers Local 0198. The next number, 005 in the example, is an internal number used in processing the wage determination. The date, 07/01/2011, following these characters is the effective date of the most current negotiated rate/collective bargaining agreement which would be July 1, 2011 in the above example.

Union prevailing wage rates will be updated to reflect any changes in the collective bargaining agreements governing the rates.

0000/9999: weighted union wage rates will be published annually each January.

Non-Union Identifiers

Classifications listed under an "SU" identifier were derived from survey data by computing average rates and are not union rates; however, the data used in computing these rates may include both union and non-union data. Example: SULA2004-007 5/13/2010. SU indicates the rates are not union majority rates, LA indicates the State of Louisiana; 2004 is the year of the survey; and 007 is an internal number used in producing the wage determination. A 1993 or later date, 5/13/2010, indicates the classifications and rates under that identifier were issued as a General Wage Determination on that date.

Survey wage rates will remain in effect and will not change until a new survey is conducted.

WAGE DETERMINATION APPEALS PROCESS

1.) Has there been an initial decision in the matter? This can be:

an existing published wage determination

a survey underlying a wage determination

a Wage and Hour Division letter setting forth a position on a wage determination matter

a conformance (additional classification and rate) ruling

On survey related matters, initial contact, including requests for summaries of surveys, should be with the Wage and Hour Regional Office for the area in which the survey was conducted because those Regional Offices have responsibility for the Davis-Bacon survey program. If the response from this initial contact is not satisfactory, then the process described in 2.) and 3.) should be followed.

With regard to any other matter not yet ripe for the formal process described here, initial contact should be with the Branch of Construction Wage Determinations. Write to: Branch of Construction Wage Determinations

Wage and Hour Division
U.S. Department of Labor
200 Constitution Avenue, N.W.
Washington, DC 20210

2.) If the answer to the question in 1.) is yes, then an interested party (those affected by the action) can request review and reconsideration from the Wage and Hour Administrator (See 29 CFR Part 1.8 and 29 CFR Part 7). Write to:

Wage and Hour Administrator
U.S. Department of Labor
200 Constitution Avenue, N.W.
Washington, DC 20210

The request should be accompanied by a full statement of the interested party's position and by any information (wage payment data, project description, area practice material, etc.) that the requestor considers relevant to the issue.

3.) If the decision of the Administrator is not favorable, an interested party may appeal directly to the Administrative Review Board (formerly the Wage Appeals Board). Write to:

Administrative Review Board
U.S. Department of Labor
200 Constitution Avenue, N.W.
Washington, DC 20210

4.) All decisions by the Administrative Review Board are final.

END OF GENERAL DECISION

Exhibit 31(a)1

THE SOUTHERN COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Thomas A. Fanning, certify that:

1. I have reviewed this quarterly report on Form 10-Q of The Southern Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2017

/s/Thomas A. Fanning

Thomas A. Fanning

Chairman, President and
Chief Executive Officer

Exhibit 31(a)2

THE SOUTHERN COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Art P. Beattie, certify that:

1. I have reviewed this quarterly report on Form 10-Q of The Southern Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: August 1, 2017

/s/Art P. Beattie

Art P. Beattie

Executive Vice President and Chief Financial Officer

Exhibit 31(b)1

ALABAMA POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Mark A. Crosswhite, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Alabama Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2017

/s/Mark A. Crosswhite

Mark A. Crosswhite

Chairman, President and Chief Executive Officer

Exhibit 31(b)2

ALABAMA POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Philip C. Raymond, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Alabama Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2017

/s/Philip C. Raymond

Philip C. Raymond
Executive Vice President, Chief Financial Officer
and Treasurer

Exhibit 31(c)1

GEORGIA POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, W. Paul Bowers, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Georgia Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2017

/s/W. Paul Bowers

W. Paul Bowers
Chairman, President and Chief Executive Officer

Exhibit 31(c)2

GEORGIA POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, W. Ron Hinson, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Georgia Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2017

/s/W. Ron Hinson

W. Ron Hinson

Executive Vice President, Chief Financial Officer and Treasurer

Exhibit 31(d)1

GULF POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, S. W. Connally, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Gulf Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2017

/s/S. W. Connally, Jr.

S. W. Connally, Jr.

Chairman, President and Chief Executive Officer

Exhibit 31(d)2

GULF POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Xia Liu, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Gulf Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2017

/s/Xia Liu

Xia Liu
Vice President, Chief Financial Officer, and
Treasurer

Exhibit 31(e)1

MISSISSIPPI POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Anthony L. Wilson, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Mississippi Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2017

/s/Anthony L. Wilson

Anthony L. Wilson

Chairman, President and
Chief Executive Officer

Exhibit 31(e)2

MISSISSIPPI POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Moses H. Feagin, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Mississippi Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2017

/s/Moses H. Feagin

Moses H. Feagin

Vice President, Treasurer and
Chief Financial Officer

Exhibit 31(f)1

SOUTHERN POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Joseph A. Miller, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Southern Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2017

/s/Joseph A. Miller

Joseph A. Miller

Chairman, President and Chief Executive Officer

Exhibit 31(f)2

SOUTHERN POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, William C. Grantham, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Southern Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2017

/s/William C. Grantham

William C. Grantham

Senior Vice President, Treasurer and Chief Financial Officer

Exhibit 31(g)1

SOUTHERN COMPANY GAS

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Andrew W. Evans, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Southern Company Gas;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   - (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   - (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
   - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: August 1, 2017

/s/Andrew W. Evans

Andrew W. Evans

Chairman, President and Chief Executive Officer

Exhibit 31(g)2

SOUTHERN COMPANY GAS

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Elizabeth W. Reese, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Southern Company Gas;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2017

/s/Elizabeth W. Reese

Elizabeth W. Reese

Executive Vice President and
Chief Financial Officer

Exhibit 32(a)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Quarterly Report on Form 10-Q of The Southern Company for the quarter ended June 30, 2017, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Quarterly Report on Form 10-Q of The Southern Company for the quarter ended June 30, 2017, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Quarterly Report on Form 10-Q of The Southern Company for the quarter ended June 30, 2017, fairly presents, in all material respects, the financial condition and results of operations of The Southern Company.

/s/Thomas A. Fanning

Thomas A. Fanning
Chairman, President and
Chief Executive Officer

/s/Art P. Beattie

Art P. Beattie
Executive Vice President and
Chief Financial Officer

August 1, 2017

Exhibit 32(b)

CERTIFICATION

**18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

In connection with the accompanying Quarterly Report on Form 10-Q of Alabama Power Company for the quarter ended June 30, 2017, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Quarterly Report on Form 10-Q of Alabama Power Company for the quarter ended June 30, 2017, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Quarterly Report on Form 10-Q of Alabama Power Company for the quarter ended June 30, 2017, fairly presents, in all material respects, the financial condition and results of operations of Alabama Power Company.

/s/Mark A. Crosswhite

Mark A. Crosswhite
Chairman, President and Chief Executive Officer

/s/Philip C. Raymond

Philip C. Raymond
Executive Vice President,
Chief Financial Officer and Treasurer

August 1, 2017

Exhibit 32(c)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Quarterly Report on Form 10-Q of Georgia Power Company for the quarter ended June 30, 2017, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Quarterly Report on Form 10-Q of Georgia Power Company for the quarter ended June 30, 2017, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Quarterly Report on Form 10-Q of Georgia Power Company for the quarter ended June 30, 2017, fairly presents, in all material respects, the financial condition and results of operations of Georgia Power Company.

/s/W. Paul Bowers

W. Paul Bowers
Chairman, President and Chief Executive Officer

/s/W. Ron Hinson

W. Ron Hinson
Executive Vice President, Chief Financial Officer and Treasurer

August 1, 2017

Exhibit 32(d)

CERTIFICATION

**18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

In connection with the accompanying Quarterly Report on Form 10-Q of Gulf Power Company for the quarter ended June 30, 2017, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Quarterly Report on Form 10-Q of Gulf Power Company for the quarter ended June 30, 2017, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Quarterly Report on Form 10-Q of Gulf Power Company for the quarter ended June 30, 2017, fairly presents, in all material respects, the financial condition and results of operations of Gulf Power Company.

/s/S. W. Connally, Jr.
S. W. Connally, Jr.
Chairman, President and Chief Executive Officer

/s/Xia Liu
Xia Liu
Vice President, Chief Financial Officer, and Treasurer

August 1, 2017

Exhibit 32(e)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Quarterly Report on Form 10-Q of Mississippi Power Company for the quarter ended June 30, 2017, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Quarterly Report on Form 10-Q of Mississippi Power Company for the quarter ended June 30, 2017, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Quarterly Report on Form 10-Q of Mississippi Power Company for the quarter ended June 30, 2017, fairly presents, in all material respects, the financial condition and results of operations of Mississippi Power Company.

/s/Anthony L. Wilson
Anthony L. Wilson
Chairman, President and Chief Executive Officer

/s/Moses H. Feagin
Moses H. Feagin
Vice President, Treasurer and
Chief Financial Officer

August 1, 2017

Exhibit 32(f)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Quarterly Report on Form 10-Q of Southern Power Company for the quarter ended June 30, 2017, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Quarterly Report on Form 10-Q of Southern Power Company for the quarter ended June 30, 2017, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Quarterly Report on Form 10-Q of Southern Power Company for the quarter ended June 30, 2017, fairly presents, in all material respects, the financial condition and results of operations of Southern Power Company.

/s/Joseph A. Miller

Joseph A. Miller
Chairman, President and Chief Executive Officer

/s/William C. Grantham

William C. Grantham
Senior Vice President, Treasurer and
Chief Financial Officer

August 1, 2017

Exhibit 32(g)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Quarterly Report on Form 10-Q of Southern Company Gas for the quarter ended June 30, 2017, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Quarterly Report on Form 10-Q of Southern Company Gas for the year ended June 30, 2017, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Quarterly Report on Form 10-Q of Southern Company Gas Company for the year ended June 30, 2017, fairly presents, in all material respects, the financial condition and results of operations of Southern Company Gas.

/s/Andrew W. Evans
Andrew W. Evans
Chairman, President and Chief Executive Officer

/s/Elizabeth W. Reese
Elizabeth W. Reese
Executive Vice President and
Chief Financial Officer

August 1, 2017

Certified a True Copy

Secretary
GULF POWER COMPANY

Exhibit B (1)

GULF POWER COMPANY
Statement of Sources and Uses of Funds
Forecast for the Year Ended December 31, 2018
(Thousands of Dollars)

	Amount
Operating Activities:	
Depreciation	191,528
Deferred Income Taxes	16,327
Other, excluding Net Income	24,640
	232,495
Investing Activities:	
Construction Expenditures	(212,872)
Other Investing Activities	(20,288)
	(233,160)
Financing Activities:	
Issuance of Common Stock to or Capital Contributions by Parent Company	(6,730)
Pollution Control Obligations - Issued	0
Pollution Control Obligations - Retirements	0
Senior Notes - Issued	0
Senior Notes - Retirements	0
Interim Indebtedness	8,395
Dividends on Preferred Stock	0
Dividends on Common Stock	(138,000)
Other financing activities	0
	(136,335)
Total Cash Flows, excluding Net Income Before Preference Dividends	(137,000)

GULF POWER COMPANY
CONSTRUCTION BUDGET FOR GROSS PROPERTY ADDITIONS
Forecast for the Year Ended December 31, 2018
(Thousands of Dollars)

Generating Facilities	93,106
New Business Facilities	32,797
Transmission Plant Additions	35,415
Distribution Plant Additions	37,316
General Plant Additions	14,609
Total Direct Capital Expenditures	213,243
Less AFUDC - Equity	(371)
Total Projected Gross Property Additions, excluding AFUDC - Equity	212,872