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Gulf Power

Robert L. McGee, Jr.

March 28, 2017

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

RE: Docket No. 150195-EI, Order Number PSC-15-0532-FOF-EI
Application of Gulf Power Company for authority to receive common equity contributions and to issue and sell securities

Dear Ms. Stauffer:

Pursuant to Rule-25-8.009, enclosed is an original and three copies of the Consummation Report dated March 28, 2017, for official filing in the above-referenced docket.

Sincerely,

Robert L. McGee, Jr.
Regulatory and Pricing Manager

md

Enclosures

cc w/encl: Beggs & Lane
Jeffrey A. Stone, Esq
Southern Company Services
Melissa Caen

COM
AFD 2
APA
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GCL 1
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TEL
CLK

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Application of Gulf Power Company for authority to receive common equity contributions and to issue and sell securities.	)))))	Docket No. 150195-EI Filed: March 28, 2017

CONSUMMATION REPORT

GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned representative, and pursuant to Rule 25-8.009, Florida Administrative Code, and the reporting requirements of Order No. PSC-15-0532-FOF-EI entered in Docket No. 150195-EI on November 16, 2015, hereby reports for the fiscal year ending December 31, 2016:

A. The Company had 5,642,717 shares of Common Stock outstanding at the end of 2015 and 2016.

B. At the end of 2016, the Company had $280 million of lines of credit with banks subject to renewal each year. The Company borrows primarily through a commercial paper program that has the liquidity support of committed bank credit arrangements. The Company may also borrow through various other arrangements with banks. As of December 31, 2016, the Company had short-term debt through the commercial paper program in the amount of $168 million.

Pursuant to Rule 25-8.009, F.A.C., Gulf Power Company submits the following documents relative to the issuance of the above referenced notes:

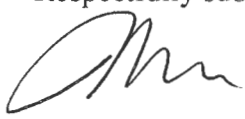
A. Exhibits Common For all Issues

1. Form S-3 Registration Statement No. 333-21146 as filed on May 17, 2016 under the Securities Act of 1933.
2. 10-K for the year ended December 31, 2016, filed with the Securities and Exchange

Commission, File No. 001-03526.

For information related to statements of capitalization, pretax interest coverage, and debt interest and preferred stock dividend requirements, please see Exhibit A. 2.

Respectfully submitted,



Josh J. Mason
Assistant Treasurer, Financial Planning & Budgeting Manager

Dated March 28, 2017

As filed with the Securities and Exchange Commission on May 17, 2016.
Subject to Amendment.

Registration No. 333-211416

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM S-3

REGISTRATION STATEMENT UNDER THE SECURITIES ACT OF 1933

Gulf Power Company	Florida	59-0276810
(Exact name of registrant as specified in its Charter)	(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

500 Bayfront Parkway
Pensacola, Florida 32520
(850) 444-6111
(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

SUSAN D. RITENOUR
Secretary and Treasurer
Gulf Power Company
One Energy Place
Pensacola, Florida 32520
(850) 444-6111
(Name, address, including zip code, and telephone number, including area code, of agent for service)

The Commission is requested to mail signed copies of all orders, notices and communications to:

ART P. BEATTIE	MELISSA K. CAEN	ERIC A. KOONTZ
Executive Vice President and	Vice President, Deputy	TROUTMAN SANDERS LLP
Chief Financial Officer	General Counsel and Corporate Secretary	600 Peachtree Street, N.E.
THE SOUTHERN COMPANY	SOUTHERN COMPANY SERVICES, INC.	Suite 5200
30 Ivan Allen Jr. Blvd., N.W.	30 Ivan Allen Jr. Blvd., N.W.	Atlanta, Georgia 30308-2216
Atlanta, Georgia 30308	Atlanta, Georgia 30308	

Approximate date of commencement of proposed sale to the public: From time to time after the effective date of this registration statement.

If the only securities being registered on this Form are being offered pursuant to dividend or interest reinvestment plans, please check the following box. ☐

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, other than securities offered only in connection with dividend or interest reinvestment plans, check the following box: ☒

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, please check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐_____

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐_____

If this Form is a registration statement pursuant to General Instruction I.D. or a post-effective amendment thereto that shall become effective upon filing with the Commission pursuant to Rule 462(e) under the Securities Act, check the following box. ☐

If this Form is a post-effective amendment to a registration statement filed pursuant to General Instruction I.D. filed to register additional securities or additional classes of securities pursuant to Rule 413(b) under the Securities Act, check the following box. ☐

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):

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☒ (Do not check if a smaller reporting company)	Smaller reporting company	☐

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered	Amount to be Registered(1)	Proposed Maximum Offering Price Per Unit(1)(2)(3)	Proposed Maximum Aggregate Offering Price(1)(2)(3)	Amount of Registration Fee(1)
Gulf Power Company Class A Preferred Stock				
Gulf Power Company Preference Stock				
Gulf Power Company Senior Notes				
Gulf Power Company Junior Subordinated Notes				
Total	$475,000,000	100%	$475,000,000(4)	$64,790(4)

(1) There are being registered hereunder such presently indeterminate number of shares of Preference Stock and Class A Preferred Stock and such presently indeterminate principal amount of Senior Notes and Junior Subordinated Notes of Gulf Power Company with an aggregate initial offering price not to exceed $475,000,000. Pursuant to Rule 457(o) under the Securities Act of 1933, which permits the registration fee to be calculated on the basis of the maximum offering price of all the securities listed, the table does not specify by each class information as to the amount to be registered, proposed maximum offering price per unit or proposed maximum aggregate offering price.

(2) Estimated solely for the purpose of determining the registration fee.

(3) Exclusive of accrued interest and distributions, if any.

(4) Gulf Power Company filed a Registration Statement on Form S-3 (File No. 333-188623) (the "Prior Registration Statement"), which registered an aggregate of $815,000,000 of securities, including Class A Preferred Stock, Preference Stock, Senior Notes and Junior Subordinated Notes, $475,000,000 of which remain unsold (the "Unsold Securities"). Pursuant to Rule 415(a)(6) under the Securities Act of 1933, as amended, this Registration Statement includes the Unsold Securities and Gulf Power Company is continuing to apply the previously paid filing fee of $64,790 associated with the Unsold Securities to the Unsold Securities. No securities in addition to the Unsold Securities are included in this Registration Statement. Accordingly, no additional filing fee is being paid herewith. Pursuant to Rule 415(a)(6), the offering of securities under the Prior Registration Statement will be deemed terminated as of the date of effectiveness of this Registration Statement.

The registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until this registration statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.

SUBJECT TO COMPLETION, DATED MAY 17, 2016

PROSPECTUS

$475,000,000

Gulf Power Company

Class A Preferred Stock

Preference Stock

Senior Notes

Junior Subordinated Notes

We will provide the specific terms of these securities in supplements to this Prospectus. You should read this Prospectus and the applicable Prospectus Supplement carefully before you invest.

See "Risk Factors" on page 2 for information on certain risks related to the purchase of securities offered by this Prospectus.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this Prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

, 2016

ABOUT THIS PROSPECTUS

This Prospectus is part of a registration statement filed with the Securities and Exchange Commission (the "Commission") using a "shelf" registration process under the Securities Act of 1933, as amended (the "1933 Act"). Under the shelf process, Gulf Power Company (the "Company") may sell, in one or more transactions,

- shares of Class A preferred stock (the "Class A Preferred Stock"),
- shares of preference stock (the "Preference Stock"),
- senior notes (the "Senior Notes"), or
- junior subordinated notes (the "Junior Subordinated Notes")

in a total dollar amount not to exceed $475,000,000. This Prospectus provides a general description of those securities. Each time the Company sells securities, the Company will provide a prospectus supplement that will contain specific information about the terms of that offering ("Prospectus Supplement"). The Prospectus Supplement may also add, update or change information contained in this Prospectus. You should read this Prospectus and the applicable Prospectus Supplement together with the additional information under the heading "Available Information."

RISK FACTORS

Investing in the Company's securities involves risk. Please see the risk factors described in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2015, along with the disclosure related to risk factors contained in the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, which are incorporated by reference in this Prospectus. Before making an investment decision, you should carefully consider these risks as well as other information contained or incorporated by reference in this Prospectus.

AVAILABLE INFORMATION

The Company has filed with the Commission a registration statement on Form S-3 (the "Registration Statement," which term encompasses any amendments to the Registration Statement and exhibits to the Registration Statement) under the 1933 Act. As permitted by the rules and regulations of the Commission, this Prospectus does not contain all of the information set forth in the Registration Statement and the exhibits and schedules to the Registration Statement, to which reference is made.

The Company is subject to the informational requirements of the Securities Exchange Act of 1934, as amended (the "1934 Act"), and in accordance with the 1934 Act files reports and other information with the Commission. Such reports and other information can be inspected and copied at the Public Reference Room of the Commission at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the Commission at 1-800-SEC-0330. The Commission maintains a website that contains reports, proxy and information statements and other information regarding registrants including the Company that file electronically at http://www.sec.gov.

INCORPORATION OF CERTAIN DOCUMENTS BY REFERENCE

The following documents have been filed with the Commission pursuant to the 1934 Act and are incorporated by reference in this Prospectus and made a part of this Prospectus:

(a) the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2015; and

(b) the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016.

All documents filed by the Company with the Commission pursuant to Section 13(a), 13(c), 14 or 15(d) of the 1934 Act subsequent to the date of the initial filing of the Registration Statement and prior to the effectiveness of the

Registration Statement and subsequent to the date of this Prospectus and prior to the termination of this offering shall be deemed to be incorporated by reference in this Prospectus and made a part of this Prospectus from the date of filing of such documents; provided, however, that the Company is not incorporating any information furnished under Items 2.02 or 7.01 of any Current Report on Form 8-K unless specifically stated otherwise. Any statement contained in a document incorporated or deemed to be incorporated by reference in this Prospectus shall be deemed to be modified or superseded for purposes of this Prospectus to the extent that a statement contained in this Prospectus or in any other subsequently filed document which also is or is deemed to be incorporated by reference in this Prospectus modifies or supersedes such statement. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this Prospectus.

The Company will provide without charge to each person, including any beneficial owner, to whom this Prospectus is delivered, on the written or oral request of any such person, a copy of any or all documents incorporated by reference in this Prospectus (other than the exhibits to such documents unless such exhibits are specifically incorporated by reference in this Prospectus). Such requests should be directed to Susan D. Ritenour, Secretary and Treasurer, Gulf Power Company, One Energy Place, Pensacola, Florida 32520, telephone: (850) 444-6111.

GULF POWER COMPANY

The Company was organized under the laws of the State of Maine on November 2, 1925 and was admitted to do business in Florida on January 15, 1926, in Mississippi on October 25, 1976 and in Georgia on November 20, 1984. Effective as of November 2, 2005, the Company was domesticated as a Florida corporation. Under applicable laws of the State of Florida and the State of Maine, the Company's legal existence was uninterrupted, with only its state of incorporation changed. The principal executive offices of the Company are located at 500 Bayfront Parkway, Pensacola, Florida 32520, and the telephone number is (850) 444-6111.

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

SELECTED INFORMATION

The following material, which is presented in this Prospectus solely to furnish limited introductory information regarding the Company, has been selected from, or is based upon, the detailed information and financial statements appearing in the documents incorporated in this Prospectus by reference or elsewhere in this Prospectus, is qualified in its entirety by reference to those documents and, therefore, should be read together with those documents.

Gulf Power Company

Business	Generation, purchase, transmission, distribution and sale of electric energy
Customers at December 31, 2015	449,471
Generating Capacity at December 31, 2015 (kilowatts)	2,582,600
Sources of Generation during 2015 (kilowatt-hours)	Coal (57%), Gas (43%)

Certain Ratios

The following table sets forth the Ratios of Earnings to Fixed Charges and Earnings to Fixed Charges Plus Preference Dividend Requirements (Pre-Income Tax Basis) for the periods indicated.

	Year Ended December 31,					Three Months Ended March 31,
	2011	2012	2013	2014	2015	2016(1)
Ratio of Earnings to Fixed Charges(2)	3.22	3.72	3.93	3.98	3.94	3.64
Ratio of Earnings to Fixed Charges Plus Preference Dividend Requirements (Pre-Income Tax Basis)(3)	2.86	3.30	3.36	3.37	3.37	3.06

(1) Due to seasonal variations in the demand for energy, operating results for the three months ended March 31, 2016 do not necessarily indicate operating results for the entire year.

(2) This ratio is computed as follows: (i) "Earnings" have been calculated by adding to "Earnings Before Income Taxes" "Interest expense, net of amounts capitalized," the interest component of rental expense and the debt portion of allowance for funds used during construction; and (ii) "Fixed Charges" consist of "Interest expense, net of amounts capitalized," the interest component of rental expense and the debt portion of allowance for funds used during construction.

(3) In computing this ratio, "Preference Dividend Requirements" represent the before tax earnings necessary to pay such dividends, computed at the effective tax rates for the applicable periods.

USE OF PROCEEDS

Except as may be otherwise described in an applicable Prospectus Supplement, the net proceeds received by the Company from the sale of the Class A Preferred Stock, the Preference Stock, the Senior Notes or the Junior Subordinated Notes will be used in connection with its ongoing construction program, to pay scheduled maturities and/or refundings of its securities, to repay short-term indebtedness to the extent outstanding and for other general corporate purposes.

DESCRIPTION OF THE CLASS A PREFERRED STOCK

Set forth below is a description of the general terms of the Class A Preferred Stock. The statements in this Prospectus concerning the Class A Preferred Stock are an outline and do not purport to be complete. Such statements make use of defined terms and are qualified in their entirety by reference to the Amended and Restated Articles of Incorporation of the Company, as amended (the "Charter"), a copy of which is filed as an exhibit to the Registration Statement of which this Prospectus forms a part. The general provisions which apply to the preferred stock of the Company of all classes, which are now or may later be authorized or created, are set forth in the Charter.

General

Each series of the Class A Preferred Stock, par value $25 per share, is to be created by the Board of Directors of the Company (the "Board of Directors") through an amendment to the Charter.

As of March 31, 2016, the Company had 10,000,000 authorized shares of Class A Preferred Stock. In addition to the Class A Preferred Stock, the Company has authorized 10,000,000 shares of Preferred Stock, par value of $100 per share (the "Preferred Stock"). As of March 31, 2016, there were no outstanding shares of the Class A Preferred Stock or the Preferred Stock. The Class A Preferred Stock ranks equally with the Preferred Stock with respect to dividends and amounts payable upon liquidation, dissolution or winding up of the Company. The Class A Preferred Stock and the Preferred Stock rank senior to the Preference Stock, the Company's common stock and any other securities the Company may issue in the future that by their terms rank junior to the Class A Preferred Stock and the Preferred Stock with respect to dividends and amounts payable upon liquidation, dissolution or winding up of the Company. All shares of the Class A

Preferred Stock will rank on a parity with respect to dividends and amounts payable upon liquidation, dissolution or winding up of the Company.

The Class A Preferred Stock will not be subject to further calls or assessment by the Company.

Any proposed listing of the Class A Preferred Stock on a securities exchange will be described in the applicable Prospectus Supplement.

Transfer Agent and Registrar

Unless otherwise indicated in the applicable Prospectus Supplement, the transfer agent for the Class A Preferred Stock will be Wells Fargo Bank, National Association, P.O. Box 64856, St. Paul, MN 55154-0856, which will also serve as the registrar.

Dividend Rights and Provisions

Dividends on the Class A Preferred Stock are payable, when and if declared by the Board of Directors, at the rate per annum determined for each respective series. Unless otherwise indicated in the applicable Prospectus Supplement, dividends will be payable to holders of record of the Class A Preferred Stock as they appear on the books of the Company on the record dates fixed by the Board of Directors.

So long as any shares of the Preferred Stock or the Class A Preferred Stock are outstanding, no dividends may be declared or paid upon or set apart for the Preference Stock, the Company's common stock or any other class of stock of the Company over which the Preferred Stock and the Class A Preferred Stock have a preference as to the payment of dividends, unless: (1) full dividends on all shares of cumulative Preferred Stock and cumulative Class A Preferred Stock for all past dividend periods have been paid or declared and a sum sufficient for the payment thereof has been set apart and full dividends on such Preferred Stock and Class A Preferred Stock for the then current dividend period have been or concurrently are declared; and (2) full dividends for the then current dividend period on all shares of non-cumulative Preferred Stock and non-cumulative Class A Preferred Stock have been or contemporaneously are paid or declared and a sum sufficient for the payment thereof is set aside.

The applicable Prospectus Supplement will set forth the dividend rate provisions of the Class A Preferred Stock, including the payment dates and the rate or rates, or the method of determining the rate or rates (which may involve periodic dividend rate settings through remarketing or auction procedures or pursuant to one or more formulae, as described in the applicable Prospectus Supplement), and whether dividends shall be cumulative and, if so, from which date or dates.

Redemption Provisions

The redemption provisions applicable to the Class A Preferred Stock will be described in the applicable Prospectus Supplement.

Voting Rights

The applicable Prospectus Supplement will describe the voting rights for each series of the Class A Preferred Stock.

Liquidation Rights

Upon voluntary or involuntary liquidation, the holders of the Preferred Stock and the Class A Preferred Stock of each series, without preference among series, are entitled to receive, out of the Company's assets available for distribution to the holders of the Preferred Stock and the Class A Preferred Stock following the satisfaction of all claims ranking senior to the Preferred Stock and the Class A Preferred Stock, the amount specified to be payable on the shares of such series before any distribution of assets may be made to the holders of the Preference Stock and the Company's common stock. Available assets, if insufficient to pay such amounts to the holders of the Preferred Stock and the Class A

Preferred Stock, are to be distributed pro rata to the payment, first of the amount per share payable in the event of involuntary liquidation, second of accrued dividends, if any, and third of any premium.

Sinking Fund

The terms and conditions of a sinking or purchase fund, if any, for the benefit of the holders of the Class A Preferred Stock will be set forth in the applicable Prospectus Supplement.

Other Rights

The holders of the Class A Preferred Stock do not have any pre-emptive or conversion rights, except as otherwise described in the applicable Prospectus Supplement.

DESCRIPTION OF THE PREFERENCE STOCK

Set forth below is a description of the general terms of the Preference Stock. The statements in this Prospectus concerning the Preference Stock are an outline and do not purport to be complete. Such statements make use of defined terms and are qualified in their entirety by reference to the Charter, a copy of which is filed as an exhibit to the Registration Statement of which this Prospectus forms a part. The general provisions which apply to the Preference Stock of the Company of all classes, which are now or may later be authorized or created, are set forth in the Charter.

General

Each series of the Preference Stock, par value $100 per share, is to be created by the Board of Directors through an amendment to the Charter.

As of March 31, 2016, the Company had 10,000,000 authorized shares of Preference Stock, of which 1,500,000 shares ($150,000,000 aggregate liquidation amount) of non-cumulative Preference Stock were outstanding. In addition, as of March 31, 2016, there were no outstanding shares of the Preferred Stock or the Class A Preferred Stock. The Preference Stock ranks junior to the Preferred Stock and the Class A Preferred Stock with respect to dividends and amounts payable upon liquidation, dissolution or winding up of the Company. The Preference Stock ranks senior to the Company's common stock and to any other securities the Company may issue in the future that by their terms rank junior to the Preference Stock with respect to dividends and amounts payable upon liquidation, dissolution or winding up of the Company. All shares of the Preference Stock will rank on a parity with respect to dividends and amounts payable upon liquidation, dissolution or winding up of the Company.

The Preference Stock will not be subject to further calls or to assessment by the Company.

Any proposed listing of the Preference Stock on a securities exchange will be described in the applicable Prospectus Supplement.

Transfer Agent and Registrar

Unless otherwise indicated in the applicable Prospectus Supplement, the transfer agent for the Preference Stock will be Wells Fargo Bank, National Association, P.O. Box 64856, St. Paul, MN 55154-0856, which will also serve as the registrar.

Dividend Rights and Provisions

Dividends on the Preference Stock are payable, when and if declared by the Board of Directors, at the rate per annum determined for each respective series. Unless otherwise indicated in the applicable Prospectus Supplement, dividends will be payable to holders of record of the Preference Stock as they appear on the books of the Company on the record dates fixed by the Board of Directors.

So long as any shares of the Preferred Stock or the Class A Preferred Stock are outstanding, no dividends may be declared or paid upon or set apart for the Preference Stock, the Company's common stock or any other class of stock of the Company over which the Preferred Stock and the Class A Preferred Stock have a preference as to the payment of dividends, unless: (1) full dividends on all shares of cumulative Preferred Stock and cumulative Class A Preferred Stock for all past dividend periods have been paid or declared and a sum sufficient for the payment thereof has been set apart and full dividends on such Preferred Stock and Class A Preferred Stock for the then current dividend period have been or concurrently are declared; and (2) full dividends for the then current dividend period on all shares of non-cumulative Preferred Stock and non-cumulative Class A Preferred Stock have been or contemporaneously are paid or declared and a sum sufficient for the payment thereof is set aside.

The applicable Prospectus Supplement will set forth the dividend rate provisions of the Preference Stock, including the payment dates and the rate or rates, or the method of determining the rate or rates (which may involve periodic dividend rate settings through remarketing or auction procedures or pursuant to one or more formulae, as described in the applicable Prospectus Supplement), and whether dividends shall be cumulative and, if so, from which date or dates.

Redemption Provisions

The redemption provisions applicable to the Preference Stock will be described in the applicable Prospectus Supplement.

Voting Rights

The applicable Prospectus Supplement will describe the voting rights for each series of the Preference Stock.

Liquidation Rights

Upon voluntary or involuntary liquidation, the holders of the Preference Stock of each series, without preference among series, are entitled to receive, out of the Company's assets available for distribution to the holders of the Preference Stock following the satisfaction of all claims ranking senior to the Preference Stock, including the claims of the holders of any outstanding shares of the Preferred Stock or the Class A Preferred Stock, the amount specified to be payable on the shares of such series before any distribution of assets may be made to the holders of the Company's common stock. Available assets, if insufficient to pay such amounts to the holders of the Preference Stock, are to be distributed pro rata to the payment, first of the amount per share payable in the event of involuntary liquidation, second of accrued dividends, if any, and third of any premium.

Sinking Fund

The terms and conditions of a sinking or purchase fund, if any, for the benefit of the holders of the Preference Stock will be set forth in the applicable Prospectus Supplement.

Other Rights

The holders of the Preference Stock do not have any pre-emptive or conversion rights, except as otherwise described in the applicable Prospectus Supplement.

DESCRIPTION OF THE SENIOR NOTES

Set forth below is a description of the general terms of the Senior Notes. The following description does not purport to be complete and is subject to, and is qualified in its entirety by reference to, the Senior Note Indenture, dated as of January 1, 1998, between the Company and Wells Fargo Bank, National Association (as successor to The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank))), as trustee (the "Senior Note Indenture Trustee"), as to be supplemented by a supplemental indenture to the Senior Note Indenture establishing the Senior Notes of each series (the Senior Note Indenture, as so supplemented, is referred to as the "Senior Note Indenture"), the forms of which are filed as exhibits to the Registration Statement of which this

Prospectus forms a part. The terms of the Senior Notes will include those stated in the Senior Note Indenture and those made a part of the Senior Note Indenture by reference to the Trust Indenture Act of 1939, as amended (the "1939 Act"). Certain capitalized terms used in this Prospectus and not defined in this Prospectus are defined in the Senior Note Indenture.

General

The Senior Notes will be issued as unsecured senior debt securities under the Senior Note Indenture and will rank equally with all other unsecured and unsubordinated debt of the Company. The Senior Notes will be effectively subordinated to any and all existing and future secured debt of the Company, aggregating approximately $41,000,000 outstanding at March 31, 2016. The Senior Note Indenture does not limit the aggregate principal amount of Senior Notes that may be issued under the Senior Note Indenture and provides that Senior Notes may be issued from time to time in one or more series pursuant to an indenture supplemental to the Senior Note Indenture. The Senior Note Indenture gives the Company the ability to reopen a previous issue of Senior Notes and issue additional Senior Notes of such series, unless otherwise provided.

Reference is made to the Prospectus Supplement that will accompany this Prospectus for the following terms of the series of Senior Notes being offered by such Prospectus Supplement: (i) the title of such Senior Notes; (ii) any limit on the aggregate principal amount of such Senior Notes; (iii) the date or dates on which the principal of such Senior Notes is payable; (iv) the rate or rates at which such Senior Notes shall bear interest, if any, or any method by which such rate or rates will be determined, the date or dates from which such interest will accrue, the interest payment dates on which such interest shall be payable, and the regular record date for the interest payable on any interest payment date; (v) the place or places where the principal of (and premium, if any, on) and interest, if any, on such Senior Notes shall be payable; (vi) the period or periods within which, the price or prices at which and the terms and conditions on which such Senior Notes may be redeemed, in whole or in part, at the option of the Company or at the option of the holder prior to their maturity; (vii) the obligation, if any, of the Company to redeem or purchase such Senior Notes; (viii) the denominations in which such Senior Notes shall be issuable; (ix) if other than the principal amount of such Senior Notes, the portion of the principal amount of such Senior Notes which shall be payable upon declaration of acceleration of the maturity of such Senior Notes; (x) any deletions from, modifications of or additions to the Events of Default or covenants of the Company as provided in the Senior Note Indenture pertaining to such Senior Notes; (xi) whether such Senior Notes shall be issued in whole or in part in the form of a Global Security; and (xii) any other terms of such Senior Notes.

The Senior Note Indenture does not contain provisions that afford holders of Senior Notes protection in the event of a highly leveraged transaction involving the Company.

Events of Default

The Senior Note Indenture provides that any one or more of the following described events with respect to the Senior Notes of any series, which has occurred and is continuing, constitutes an "Event of Default" with respect to the Senior Notes of such series:

(a) failure for 10 days to pay interest on the Senior Notes of such series when due on an interest payment date other than at maturity or upon earlier redemption; or

(b) failure to pay principal of, premium, if any, on or interest on the Senior Notes of such series when due at maturity or upon earlier redemption; or

(c) failure for three Business Days to deposit any sinking fund payment when due by the terms of a Senior Note of such series; or

(d) failure to observe or perform any other covenant or warranty of the Company in the Senior Note Indenture (other than a covenant or warranty which has expressly been included in the Senior Note Indenture solely for the benefit of one or more series of Senior Notes other than such series) for 90 days after written notice to the Company from the Senior Note Indenture Trustee or the holders of at least 25% in principal amount of the outstanding Senior Notes of such series; or

(e) certain events of bankruptcy, insolvency or reorganization of the Company; or

(f) any other default provided with respect to the Senior Notes of such series in the supplemental indenture authorizing the Senior Notes of such series.

The holders of not less than a majority in aggregate outstanding principal amount of the Senior Notes of any series have the right to direct the time, method and place of conducting any proceeding for any remedy available to the Senior Note Indenture Trustee with respect to the Senior Notes of such series. If an Event of Default occurs and is continuing with respect to the Senior Notes of any series, then the Senior Note Indenture Trustee or the holders of not less than 25% in aggregate outstanding principal amount of the Senior Notes of such series may declare the principal amount of the Senior Notes due and payable immediately by notice in writing to the Company (and to the Senior Note Indenture Trustee if given by the holders), and upon any such declaration such principal amount shall become immediately due and payable. At any time after such a declaration of acceleration with respect to the Senior Notes of any series has been made and before a judgment or decree for payment of the money due has been obtained as provided in Article Five of the Senior Note Indenture, the holders of not less than a majority in aggregate outstanding principal amount of the Senior Notes of such series may, by written notice to the Company and the Senior Note Indenture Trustee, rescind and annul such declaration and its consequences if the default has been cured or waived and the Company has paid or deposited with the Senior Note Indenture Trustee a sum sufficient to pay all matured installments of interest and principal due otherwise than by acceleration and all sums paid or advanced by the Senior Note Indenture Trustee, including reasonable compensation and expenses of the Senior Note Indenture Trustee.

The holders of not less than a majority in aggregate outstanding principal amount of the Senior Notes of any series may, on behalf of the holders of all the Senior Notes of such series, waive any past default with respect to such series, except (i) a default in the payment of principal or interest or (ii) a default in respect of a covenant or provision which under Article Nine of the Senior Note Indenture cannot be modified or amended without the consent of the holder of each outstanding Senior Note of such series affected.

Registration and Transfer

The Company shall not be required to (i) issue, register the transfer of or exchange Senior Notes of any series during a period of 15 days immediately preceding the date notice is given identifying the Senior Notes of such series called for redemption or (ii) issue, register the transfer of or exchange any Senior Notes so selected for redemption, in whole or in part, except the unredeemed portion of any Senior Note being redeemed in part.

Payment and Paying Agent

Unless otherwise indicated in an applicable Prospectus Supplement, payment of principal of any Senior Notes will be made only against surrender to the Paying Agent of such Senior Notes. Principal of and interest on Senior Notes will be payable, subject to any applicable laws and regulations, at the office of such Paying Agent or Paying Agents as the Company may designate from time to time, except that, at the option of the Company, payment of any interest may be made by wire transfer or other electronic transfer or by check mailed to the address of the person entitled to an interest payment as such address shall appear in the Security Register with respect to the Senior Notes. Payment of interest on Senior Notes on any interest payment date will be made to the person in whose name the Senior Notes (or predecessor security) are registered at the close of business on the record date for such interest payment.

Unless otherwise indicated in an applicable Prospectus Supplement, the Senior Note Indenture Trustee will act as Paying Agent with respect to the Senior Notes. The Company may at any time designate additional Paying Agents or rescind the designation of any Paying Agents or approve a change in the office through which any Paying Agent acts.

All moneys paid by the Company to a Paying Agent for the payment of the principal of or interest on the Senior Notes of any series which remain unclaimed at the end of two years after such principal or interest shall have become due and payable will be repaid to the Company, and the holder of such Senior Notes will from that time forward look only to the Company for payment of such principal and interest.

Modification

The Senior Note Indenture contains provisions permitting the Company and the Senior Note Indenture Trustee, with the consent of the holders of not less than a majority in principal amount of the outstanding Senior Notes of each

series that is affected, to modify the Senior Note Indenture or the rights of the holders of the Senior Notes of such series; provided that no such modification may, without the consent of the holder of each outstanding Senior Note that is affected, (i) change the stated maturity of the principal of, or any installment of principal of or interest on, any Senior Note, or reduce the principal amount of any Senior Note or the rate of interest on any Senior Note or any premium payable upon the redemption thereof, or change the method of calculating the rate of interest on any Senior Note, or impair the right to institute suit for the enforcement of any such payment on or after the stated maturity of any Senior Note (or, in the case of redemption, on or after the redemption date), or (ii) reduce the percentage of principal amount of the outstanding Senior Notes of any series, the consent of whose holders is required for any such supplemental indenture, or the consent of whose holders is required for any waiver (of compliance with certain provisions of the Senior Note Indenture or certain defaults under the Senior Note Indenture and their consequences) provided for in the Senior Note Indenture, or (iii) modify any of the provisions of the Senior Note Indenture relating to supplemental indentures, waiver of past defaults, or waiver of certain covenants, except to increase any such percentage or to provide that certain other provisions of the Senior Note Indenture cannot be modified or waived without the consent of the holder of each outstanding Senior Note that is affected.

In addition, the Company and the Senior Note Indenture Trustee may execute, without the consent of any holders of Senior Notes, any supplemental indenture for certain other usual purposes, including the creation of any new series of Senior Notes.

Consolidation, Merger and Sale

The Company shall not consolidate with or merge into any other corporation or convey, transfer or lease its properties and assets substantially as an entirety to any person, unless (1) such other corporation or person is a corporation organized and existing under the laws of the United States, any state in the United States or the District of Columbia and such other corporation or person expressly assumes, by supplemental indenture executed and delivered to the Senior Note Indenture Trustee, the payment of the principal of (and premium, if any, on) and interest on all the Senior Notes and the performance of every covenant of the Senior Note Indenture on the part of the Company to be performed or observed; (2) immediately after giving effect to such transactions, no Event of Default, and no event which, after notice or lapse of time or both, would become an Event of Default, shall have happened and be continuing; and (3) the Company has delivered to the Senior Note Indenture Trustee an officers' certificate and an opinion of counsel, each stating that such transaction complies with the provisions of the Senior Note Indenture governing consolidation, merger, conveyance, transfer or lease and that all conditions precedent to the transaction have been complied with.

Information Concerning the Senior Note Indenture Trustee

The Senior Note Indenture Trustee, prior to an Event of Default with respect to Senior Notes of any series, undertakes to perform, with respect to Senior Notes of such series, only such duties as are specifically set forth in the Senior Note Indenture and, in case an Event of Default with respect to Senior Notes of any series has occurred and is continuing, shall exercise, with respect to Senior Notes of such series, the same degree of care as a prudent individual would exercise in the conduct of his or her own affairs. Subject to such provision, the Senior Note Indenture Trustee is under no obligation to exercise any of the powers vested in it by the Senior Note Indenture at the request of any holder of Senior Notes of any series, unless offered reasonable indemnity by such holder against the costs, expenses and liabilities which might be incurred by the Senior Note Indenture Trustee. The Senior Note Indenture Trustee is not required to expend or risk its own funds or otherwise incur any financial liability in the performance of its duties if the Senior Note Indenture Trustee reasonably believes that repayment or adequate indemnity is not reasonably assured to it.

Wells Fargo Bank, National Association, the Senior Note Indenture Trustee, may also serve as Subordinated Note Indenture Trustee. The Company and certain of its affiliates maintain deposit accounts and banking relationships with Wells Fargo Bank, National Association and certain of its affiliates also serve as trustee under other indentures pursuant to which securities of certain affiliates of the Company are outstanding.

Governing Law

The Senior Note Indenture and the Senior Notes will be governed by, and construed in accordance with, the internal laws of the State of New York.

Miscellaneous

The Company will have the right at all times to assign any of its rights or obligations under the Senior Note Indenture to a direct or indirect wholly-owned subsidiary of the Company; provided, that, in the event of any such assignment, the Company will remain primarily liable for all such obligations. Subject to the foregoing, the Senior Note Indenture will be binding upon and inure to the benefit of the parties to the Senior Note Indenture and their respective successors and assigns.

DESCRIPTION OF THE JUNIOR SUBORDINATED NOTES

Set forth below is a description of the general terms of the Junior Subordinated Notes. The following description does not purport to be complete and is subject to, and is qualified in its entirety by reference to, the Subordinated Note Indenture to be entered into between the Company and the trustee named in the Subordinated Note Indenture (the "Subordinated Note Indenture Trustee"), as to be supplemented by a supplemental indenture to the Subordinated Note Indenture establishing the Junior Subordinated Notes of each series (the Subordinated Note Indenture, as so supplemented, is referred to as the "Subordinated Note Indenture"), the forms of which are filed as exhibits to the Registration Statement of which this Prospectus forms a part. The terms of the Junior Subordinated Notes will include those stated in the Subordinated Note Indenture and those made a part of the Subordinated Note Indenture by reference to the 1939 Act. Certain capitalized terms used in this Prospectus and not defined in this Prospectus are defined in the Subordinated Note Indenture.

General

The Junior Subordinated Notes will be issued as unsecured junior subordinated debt securities under the Subordinated Note Indenture. The Subordinated Note Indenture does not limit the aggregate principal amount of Junior Subordinated Notes that may be issued under the Subordinated Note Indenture and provides that Junior Subordinated Notes may be issued from time to time in one or more series pursuant to an indenture supplemental to the Subordinated Note Indenture. The Subordinated Note Indenture gives the Company the ability to reopen a previous issue of Junior Subordinated Notes and issue additional Junior Subordinated Notes of such series, unless otherwise provided.

Reference is made to the Prospectus Supplement that will accompany this Prospectus for the following terms of the series of Junior Subordinated Notes being offered by such Prospectus Supplement: (i) the title of such Junior Subordinated Notes; (ii) any limit on the aggregate principal amount of such Junior Subordinated Notes; (iii) the date or dates on which the principal of such Junior Subordinated Notes is payable; (iv) the rate or rates at which such Junior Subordinated Notes shall bear interest, if any, or any method by which such rate or rates will be determined, the date or dates from which such interest will accrue, the interest payment dates on which such interest shall be payable, and the regular record date for the interest payable on any interest payment date; (v) the place or places where the principal of, premium, if any, on and interest, if any, on such Junior Subordinated Notes shall be payable; (vi) the period or periods within which, the price or prices at which and the terms and conditions on which such Junior Subordinated Notes may be redeemed, in whole or in part, at the option of the Company or at the option of the holder prior to their maturity; (vii) the obligation, if any, of the Company to redeem or purchase such Junior Subordinated Notes; (viii) the denominations in which such Junior Subordinated Notes shall be issuable; (ix) if other than the principal amount of such Junior Subordinated Notes, the portion of the principal amount of such Junior Subordinated Notes which shall be payable upon declaration of acceleration of the maturity of such Junior Subordinated Notes; (x) any deletions from, modifications of or additions to the Events of Default or covenants of the Company as provided in the Subordinated Note Indenture pertaining to such Junior Subordinated Notes; (xi) whether such Junior Subordinated Notes shall be issued in whole or in part in the form of a Global Security; (xii) the right, if any, of the Company to extend the interest payment periods of such Junior Subordinated Notes; and (xiii) any other terms of such Junior Subordinated Notes.

The Subordinated Note Indenture does not contain provisions that afford holders of Junior Subordinated Notes protection in the event of a highly leveraged transaction involving the Company.

Subordination

The Junior Subordinated Notes are subordinated and junior in right of payment to all Senior Indebtedness (as defined below) of the Company. No payment of principal of (including redemption payments, if any), or premium, if any, on or interest on (including Additional Interest (as defined below)) the Junior Subordinated Notes may be made if (a) any Senior Indebtedness is not paid when due and any applicable grace period with respect to such default has ended with such default not being cured or waived or otherwise ceasing to exist, or (b) the maturity of any Senior Indebtedness has been accelerated because of a default, or (c) notice has been given of the exercise of an option to require repayment, mandatory payment or prepayment or otherwise of the Senior Indebtedness. Upon any payment or distribution of assets of the Company to creditors upon any liquidation, dissolution, winding-up, reorganization, assignment for the benefit of creditors, marshalling of assets or liabilities, or any bankruptcy, insolvency or similar proceedings of the Company, the holders of Senior Indebtedness shall be entitled to receive payment in full of all amounts due or to become due on or in respect of all Senior Indebtedness before the holders of the Junior Subordinated Notes are entitled to receive or retain any payment or distribution. Subject to the prior payment of all Senior Indebtedness, the rights of the holders of the Junior Subordinated Notes will be subrogated to the rights of the holders of Senior Indebtedness to receive payments and distributions applicable to such Senior Indebtedness until all amounts owing on the Junior Subordinated Notes are paid in full.

The term "Senior Indebtedness" means, with respect to the Company, (i) any payment due in respect of indebtedness of the Company, whether outstanding at the date of execution of the Subordinated Note Indenture or incurred, created or assumed after such date, (a) in respect of money borrowed (including any financial derivative, hedging or futures contract or similar instrument) and (b) evidenced by securities, debentures, bonds, notes or other similar instruments issued by the Company that, by their terms, are senior or senior subordinated debt securities including, without limitation, all such obligations under its indentures with various trustees; (ii) all capital lease obligations; (iii) all obligations issued or assumed as the deferred purchase price of property, all conditional sale obligations and all obligations of the Company under any title retention agreement (but excluding trade accounts payable arising in the ordinary course of business and long-term purchase obligations); (iv) all obligations for the reimbursement of any letter of credit, banker's acceptance, security purchase facility or similar credit transaction; (v) all obligations of the type referred to in clauses (i) through (iv) above of other persons the payment of which the Company is responsible or liable as obligor, guarantor or otherwise; and (vi) all obligations of the type referred to in clauses (i) through (v) above of other persons secured by any lien on any property or asset of the Company (whether or not such obligation is assumed by the Company), except for (1) any such indebtedness that is by its terms subordinated to or that ranks equally with the Junior Subordinated Notes and (2) any unsecured indebtedness between or among the Company or its affiliates. Such Senior Indebtedness shall continue to be Senior Indebtedness and be entitled to the benefits of the subordination provisions contained in the Subordinated Note Indenture irrespective of any amendment, modification or waiver of any term of such Senior Indebtedness.

The Subordinated Note Indenture does not limit the aggregate amount of Senior Indebtedness that may be issued by the Company. As of March 31, 2016, Senior Indebtedness of the Company aggregated approximately $1,375,000,000.

Additional Interest

"Additional Interest" is defined in the Subordinated Note Indenture as any interest due and not paid on an interest payment date, together with interest on such interest due from such interest payment date to the date of payment, compounded quarterly, on each interest payment date.

Certain Covenants

The Company covenants in the Subordinated Note Indenture, for the benefit of the holders of each series of Junior Subordinated Notes, that, (i) if at such time the Company shall have given notice of its election to extend an interest payment period for such series of Junior Subordinated Notes and such extension shall be continuing or (ii) if at such time an Event of Default under the Subordinated Note Indenture with respect to such series of Junior Subordinated Notes shall have occurred and be continuing, (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 on, principal of or premium, if any, on or repay, repurchase or

redeem any debt securities (including guarantees) issued by the Company which rank equally with or junior to the Junior Subordinated Notes. None of the foregoing, however, shall 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 or (iii) dividends, payments or distributions payable in shares of capital stock.

Events of Default

The Subordinated Note Indenture provides that any one or more of the following described events with respect to the Junior Subordinated Notes of any series, which has occurred and is continuing, constitutes an "Event of Default" with respect to the Junior Subordinated Notes of such series:

(a) failure for 10 days to pay interest on the Junior Subordinated Notes of such series, including any Additional Interest in respect of the Junior Subordinated Notes of such series, when due on an interest payment date other than at maturity or upon earlier redemption; provided, however, that a valid extension of the interest payment period by the Company shall not constitute a default in the payment of interest for this purpose; or

(b) failure to pay principal of, or premium, if any, on or interest, including Additional Interest, on the Junior Subordinated Notes of such series when due at maturity or upon earlier redemption; or

(c) failure for three Business Days to deposit any sinking fund payment when due by the terms of a Junior Subordinated Note of such series; or

(d) failure to observe or perform any other covenant or warranty of the Company in the Subordinated Note Indenture (other than a covenant or warranty which has expressly been included in the Subordinated Note Indenture solely for the benefit of one or more series of Junior Subordinated Notes other than such series) for 90 days after written notice to the Company from the Subordinated Note Indenture Trustee or the holders of at least 25% in principal amount of the outstanding Junior Subordinated Notes of such series; or

(e) certain events of bankruptcy, insolvency or reorganization of the Company; or

(f) any other default provided with respect to the Junior Subordinated Notes of such series in the supplemental indenture authorizing the Junior Subordinated Notes of such series.

The holders of not less than a majority in aggregate outstanding principal amount of the Junior Subordinated Notes of any series have the right to direct the time, method and place of conducting any proceeding for any remedy available to the Subordinated Note Indenture Trustee with respect to the Junior Subordinated Notes of such series. If a Subordinated Note Indenture Event of Default occurs and is continuing with respect to the Junior Subordinated Notes of any series, then the Subordinated Note Indenture Trustee or the holders of not less than 25% in aggregate outstanding principal amount of the Junior Subordinated Notes of such series may declare the principal amount of the Junior Subordinated Notes due and payable immediately by notice in writing to the Company (and to the Subordinated Note Indenture Trustee if given by the holders), and upon any such declaration such principal amount shall become immediately due and payable. At any time after such a declaration of acceleration with respect to the Junior Subordinated Notes of any series has been made and before a judgment or decree for payment of the money due has been obtained as provided in Article Five of the Subordinated Note Indenture, the holders of not less than a majority in aggregate outstanding principal amount of the Junior Subordinated Notes of such series may, by written notice to the Company and the Subordinated Note Indenture Trustee, rescind and annul such declaration and its consequences if the default has been cured or waived and the Company has paid or deposited with the Subordinated Note Indenture Trustee a sum sufficient to pay all matured installments of interest (including any Additional Interest) and principal due otherwise than by acceleration and all sums paid or advanced by the Subordinated Note Indenture Trustee, including reasonable compensation and expenses of the Subordinated Note Indenture Trustee.

The holders of not less than a majority in aggregate outstanding principal amount of the Junior Subordinated Notes of any series may, on behalf of the holders of all the Junior Subordinated Notes of such series, waive any past default with respect to such series, except (i) a default in the payment of principal or interest or (ii) a default in respect of a

covenant or provision which under Article Nine of the Subordinated Note Indenture cannot be modified or amended without the consent of the holder of each outstanding Junior Subordinated Note of such series affected.

Registration and Transfer

The Company shall not be required to (i) issue, register the transfer of or exchange Junior Subordinated Notes of any series during a period of 15 days immediately preceding the date notice is given identifying the Junior Subordinated Notes of such series called for redemption or (ii) issue, register the transfer of or exchange any Junior Subordinated Notes so selected for redemption, in whole or in part, except the unredeemed portion of any Junior Subordinated Note being redeemed in part.

Payment and Paying Agent

Unless otherwise indicated in an applicable Prospectus Supplement, payment of principal of any Junior Subordinated Notes will be made only against surrender to the Paying Agent of such Junior Subordinated Notes. Principal of and interest on Junior Subordinated Notes will be payable, subject to any applicable laws and regulations, at the office of such Paying Agent or Paying Agents as the Company may designate from time to time, except that, at the option of the Company, payment of any interest may be made by wire transfer or other electronic transfer or by check mailed to the address of the person entitled to an interest payment as such address shall appear in the Security Register with respect to the Junior Subordinated Notes. Payment of interest on Junior Subordinated Notes on any interest payment date will be made to the person in whose name the Junior Subordinated Notes (or predecessor security) are registered at the close of business on the record date for such interest payment.

Unless otherwise indicated in an applicable Prospectus Supplement, the Subordinated Note Indenture Trustee will act as Paying Agent with respect to the Junior Subordinated Notes. The Company may at any time designate additional Paying Agents or rescind the designation of any Paying Agents or approve a change in the office through which any Paying Agent acts.

All moneys paid by the Company to a Paying Agent for the payment of the principal of or interest on the Junior Subordinated Notes of any series which remain unclaimed at the end of two years after such principal or interest shall have become due and payable will be repaid to the Company, and the holder of such Junior Subordinated Notes will from that time forward look only to the Company for payment of such principal and interest.

Modification

The Subordinated Note Indenture contains provisions permitting the Company and the Subordinated Note Indenture Trustee, with the consent of the holders of not less than a majority in principal amount of the outstanding Junior Subordinated Notes of each series that is affected, to modify the Subordinated Note Indenture or the rights of the holders of the Junior Subordinated Notes of such series; provided, that no such modification may, without the consent of the holder of each outstanding Junior Subordinated Note that is affected, (i) change the stated maturity of the principal of, or any installment of principal of or interest on, any Junior Subordinated Note, or reduce the principal amount of any Junior Subordinated Note or the rate of interest (including Additional Interest) on any Junior Subordinated Note or any premium payable upon the redemption thereof, or change the method of calculating the rate of interest on any Junior Subordinated Note, or impair the right to institute suit for the enforcement of any such payment on or after the stated maturity of any Junior Subordinated Note (or, in the case of redemption, on or after the redemption date), or (ii) reduce the percentage of principal amount of the outstanding Junior Subordinated Notes of any series, the consent of whose holders is required for any such supplemental indenture, or the consent of whose holders is required for any waiver (of compliance with certain provisions of the Subordinated Note Indenture or certain defaults under the Subordinated Note Indenture and their consequences) provided for in the Subordinated Note Indenture, or (iii) modify any of the provisions of the Subordinated Note Indenture relating to supplemental indentures, waiver of past defaults, or waiver of certain covenants, except to increase any such percentage or to provide that certain other provisions of the Subordinated Note Indenture cannot be modified or waived without the consent of the holder of each outstanding Junior Subordinated Note that is affected, or (iv) modify the provisions of the Subordinated Note Indenture with respect to the subordination of the Junior Subordinated Notes in a manner adverse to such holder.

In addition, the Company and the Subordinated Note Indenture Trustee may execute, without the consent of any holders of Junior Subordinated Notes, any supplemental indenture for certain other usual purposes, including the creation of any new series of Junior Subordinated Notes.

Consolidation, Merger and Sale

The Company shall not consolidate with or merge into any other corporation or convey, transfer or lease its properties and assets substantially as an entirety to any person, unless (1) such other corporation or person is a corporation organized and existing under the laws of the United States, any state of the United States or the District of Columbia and such other corporation or person expressly assumes, by supplemental indenture executed and delivered to the Subordinated Note Indenture Trustee, the payment of the principal of, and premium, if any, on and interest (including Additional Interest) on all the Junior Subordinated Notes and the performance of every covenant of the Subordinated Note Indenture on the part of the Company to be performed or observed; (2) immediately after giving effect to such transactions, no Event of Default, and no event which, after notice or lapse of time or both, would become an Event of Default, shall have happened and be continuing; and (3) the Company has delivered to the Subordinated Note Indenture Trustee an officers' certificate and an opinion of counsel, each stating that such transaction complies with the provisions of the Subordinated Note Indenture governing consolidation, merger, conveyance, transfer or lease and that all conditions precedent to the transaction have been complied with.

Information Concerning the Subordinated Note Indenture Trustee

The Subordinated Note Indenture Trustee, prior to an Event of Default with respect to Junior Subordinated Notes of any series, undertakes to perform, with respect to Junior Subordinated Notes of such series, only such duties as are specifically set forth in the Subordinated Note Indenture and, in case an Event of Default with respect to Junior Subordinated Notes of any series has occurred and is continuing, shall exercise, with respect to Junior Subordinated Notes of such series, the same degree of care as a prudent individual would exercise in the conduct of his or her own affairs. Subject to such provision, the Subordinated Note Indenture Trustee is under no obligation to exercise any of the powers vested in it by the Subordinated Note Indenture at the request of any holder of Junior Subordinated Notes of any series, unless offered reasonable indemnity by such holder against the costs, expenses and liabilities which might be incurred by the Subordinated Note Indenture Trustee. The Subordinated Note Indenture Trustee is not required to expend or risk its own funds or otherwise incur any financial liability in the performance of its duties if the Subordinated Note Indenture Trustee reasonably believes that repayment or adequate indemnity is not reasonably assured to it.

The Subordinated Note Indenture Trustee may also serve as Senior Note Indenture Trustee. The Company and certain of its affiliates may maintain deposit accounts and banking relationships with the Subordinated Note Indenture Trustee. The Subordinated Note Indenture Trustee may serve as trustee under other indentures pursuant to which securities of the Company or certain affiliates of the Company are outstanding.

Governing Law

The Subordinated Note Indenture and the Junior Subordinated Notes will be governed by, and construed in accordance with, the internal laws of the State of New York.

Miscellaneous

The Company will have the right at all times to assign any of its rights or obligations under the Subordinated Note Indenture to a direct or indirect wholly-owned subsidiary of the Company; provided, that, in the event of any such assignment, the Company will remain primarily liable for all such obligations. Subject to the foregoing, the Subordinated Note Indenture will be binding upon and inure to the benefit of the parties to the Subordinated Note Indenture and their respective successors and assigns.

PLAN OF DISTRIBUTION

The Company may sell the Class A Preferred Stock, the Preference Stock, the Senior Notes and the Junior Subordinated Notes in one or more of the following ways from time to time: (i) to underwriters for resale to the public or to institutional investors; (ii) directly to institutional investors; or (iii) through agents to the public or to institutional investors. The Prospectus Supplement with respect to each series of Class A Preferred Stock, Preference Stock, Senior Notes or Junior Subordinated Notes will set forth the terms of the offering of such Class A Preferred Stock, Preference Stock, Senior Notes or Junior Subordinated Notes, including the name or names of any underwriters or agents, the purchase price of such Class A Preferred Stock, Preference Stock, Senior Notes or Junior Subordinated Notes and the proceeds to the Company from such sale, any underwriting discounts or agency fees and other items constituting underwriters' or agents' compensation, any initial public offering price, any discounts or concessions allowed or reallowed or paid to dealers and any securities exchange on which such Class A Preferred Stock, Preference Stock, Senior Notes or Junior Subordinated Notes may be listed.

If underwriters participate in the sale, such Class A Preferred Stock, Preference Stock, Senior Notes or Junior Subordinated Notes will be acquired by the underwriters for their own accounts and may be resold from time to time in one or more transactions, including negotiated transactions, at a fixed public offering price or at varying prices determined at the time of sale.

Unless otherwise set forth in the Prospectus Supplement, the obligations of the underwriters to purchase any series of Class A Preferred Stock, Preference Stock, Senior Notes or Junior Subordinated Notes will be subject to certain conditions precedent and the underwriters will be obligated to purchase all of such series of Class A Preferred Stock, Preference Stock, Senior Notes or Junior Subordinated Notes, if any are purchased.

Under agreements entered into with the Company, underwriters and agents may be entitled to indemnification against certain civil liabilities, including liabilities under the 1933 Act. Underwriters and agents and their affiliates may engage in transactions with, or perform services for, the Company in the ordinary course of business, for which they may receive customary compensation.

Each series of Class A Preferred Stock, Preference Stock, Senior Notes or Junior Subordinated Notes will be a new issue of securities and will have no established trading market. Any underwriters to whom Class A Preferred Stock, Preference Stock, Senior Notes or Junior Subordinated Notes are sold for public offering and sale may make a market in such Class A Preferred Stock, Preference Stock, Senior Notes or Junior Subordinated Notes, but such underwriters will not be obligated to do so and may discontinue any market making at any time without notice. The Class A Preferred Stock, the Preference Stock, the Senior Notes or the Junior Subordinated Notes may or may not be listed on a national securities exchange.

LEGAL MATTERS

The validity of the Class A Preferred Stock and the Preference Stock and certain matters relating to such securities will be passed upon on behalf of the Company by Beggs & Lane, a Registered Limited Liability Partnership, Pensacola, Florida, and the validity of the Senior Notes and the Junior Subordinated Notes and certain matters relating to such securities will be passed upon on behalf of the Company by Troutman Sanders LLP, Atlanta, Georgia. Certain legal matters will be passed upon for the underwriters by Hunton & Williams LLP, New York, New York. From time to time, Hunton & Williams LLP acts as counsel to affiliates of the Company for some matters.

EXPERTS

The financial statements and the related financial statement schedule incorporated in this Prospectus by reference from the Company's Annual Report on Form 10-K have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report, which is incorporated herein by reference. Such financial statements and financial statement schedule have been so incorporated in reliance upon the report of such firm given upon their authority as experts in accounting and auditing.

PART II

INFORMATION NOT REQUIRED IN PROSPECTUS

Item 14. ***Other Expenses of Issuance and Distribution.***

The estimated expenses of issuance and distribution, other than underwriting discounts and commissions, to be borne by the Company are as follows:

Fees and expenses of trustees and/or Transfer Agent and Registrar	$ 20,000
Listing fees of New York Stock Exchange	73,800
Rating Agency fees	380,000
Services of Southern Company Services, Inc.	80,000
Fees and expenses of counsel	280,000
Blue sky fees and expenses	20,000
Fees of accountants	250,000
Miscellaneous expenses	61,200
Total	$ 1,165,000

* Each Prospectus Supplement will reflect estimated expenses of the Company based upon the amount of the related offering.

Item 15. ***Indemnification of Directors and Officers.***

The Florida Business Corporation Act, as amended (the "FBCA"), provides that a corporation may indemnify any person who was or is a party to any proceeding (other than an action by, or in the right of, the corporation) by reason of the fact that he or she is or was a director, officer, employee or agent of the corporation or is or was serving at the request of the corporation as a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise against liability incurred in connection with such proceeding, including any appeal thereof, if he or she acted in good faith and in a manner he or she reasonably believed to be in, or not opposed to, the best interests of the corporation and, with respect to any criminal proceeding, had no reasonable cause to believe his or her conduct was unlawful. In the case of proceedings by or in the right of the corporation, the FBCA provides that, in general, a corporation may indemnify any person who was or is a party to such proceeding by reason of the fact that he or she is or was a director, officer, employee or agent of the corporation or is or was serving at the request of the corporation as a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise against expenses and amounts paid in settlement actually and reasonably incurred in connection with the defense or settlement of such proceeding, including the appeal thereof, provided that such person acted in good faith and in a manner he or she reasonably believed to be in, or not opposed to, the best interests of the corporation, and provided further that no indemnification shall be made in respect of any claim as to which such person is adjudged liable unless a court of competent jurisdiction determines upon application that such person is fairly and reasonably entitled to indemnity. To the extent that a director, officer, employee or agent of the corporation has been successful on the merits or otherwise in the defense of any of the proceedings described above, the FBCA provides that the corporation is required to indemnify such director, officer, employee or agent of the corporation against expenses actually and reasonably incurred in connection therewith. The FBCA provides that expenses incurred by an officer or director in defending a civil or criminal proceeding may be paid by the corporation in advance of the final disposition of such proceeding upon receipt of an undertaking by such officer or director to repay such amounts if he or she is ultimately found not to be entitled to indemnification. The FBCA provides that a corporation may make any other or further indemnification or advancement of expenses of any of its officers, directors, agents or employees under any bylaw, agreement, vote of shareholders or disinterested directors or otherwise, provided that indemnification or advancement of expenses is not permitted if a judgment or final adjudication establishes that his or her actions, or omissions to act, were material to the cause of action

and constitute: (i) a violation of criminal law, unless the director, officer, employee or agent had reasonable cause to believe his or her conduct was lawful or had no reasonable cause to believe his or her conduct was unlawful; (ii) a transaction from which the director, officer, employee or agent derived an improper personal benefit; (iii) in the case of a director, a circumstance under which the director is liable for an unlawful distribution under the FBCA; or (iv) willful misconduct or conscious disregard for the best interests of the corporation in a proceeding by or in the right of the corporation.

Section 20 of the Bylaws of the Company provides in pertinent part as follows:

To the fullest extent permitted by law, the Company shall indemnify any person made, or threatened to be made, a party to any threatened, pending, or completed claim, action, suit or proceeding, whether civil or criminal, administrative or investigative, and whether formal or informal, by reason of the fact that he is or was a director, officer or was an employee of the Company holding one or more management positions through and inclusive of managers (but not positions below the level of manager) or any such person is or was serving at the request of the Company as a director, officer, employee, or agent of another corporation, partnership, joint venture, trust, or other enterprise, against all expenses and liabilities reasonably incurred in connection with such claim, action, suit or proceeding, including any appeal thereof, if he acted in good faith and in a manner he reasonably believed to be in, or not opposed to, the best interests of the Company and, with respect to any criminal action or proceeding, had no reasonable cause to believe his conduct was unlawful. Such person shall also be entitled to advancement of expenses incurred in defending a proceeding in advance of its final disposition to the full extent permitted by law, subject to the conditions imposed by law and subject to providing the Company a written undertaking by or on behalf of such person to pay amounts advanced if it shall be ultimately determined that such person was not entitled to be indemnified by the Company under this Section or otherwise. Nothing herein shall restrict the power of the Company to provide indemnification or advancement of expenses to other employees or agents of the Company as otherwise permitted by law.

The right of indemnification under this Section shall be a contract right inuring to the benefit of the person entitled to be indemnified hereunder and no amendment or repeal of this Section shall adversely affect any right of such person existing at the time of such amendment or repeal. The indemnification provided hereunder shall inure to the benefit of the heirs, executors, personal and legal representatives, and administrators of a person entitled to indemnification hereunder.

The right of indemnification under this Section shall be in addition to and not exclusive of all other rights to which persons entitled to indemnification hereunder may be entitled. Nothing contained in this Section shall affect any rights to indemnification to which persons may be entitled by contract or otherwise under law.

The Company has an insurance policy covering its liabilities and expenses which might arise in connection with its lawful indemnification of its directors and officers for certain of their liabilities and expenses and also covering its officers and directors against certain other liabilities and expenses.

Item 16. ***Exhibits.***

Exhibit Number	
1.1	— Form of Underwriting Agreement relating to the Class A Preferred Stock.*
1.2	— Form of Underwriting Agreement relating to the Preference Stock.*
1.3	— Form of Underwriting Agreement relating to the Senior Notes.*
1.4	— Form of Underwriting Agreement relating to the Junior Subordinated Notes.*

Exhibit Number		
4.1	—	Senior Note Indenture dated as of January 1, 1998, between Gulf Power Company and Wells Fargo Bank, National Association (as successor to The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank))), as Trustee, and indentures supplemented 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 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. 000-31737, 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.)
4.2	—	Form of Supplemental Indenture to Senior Note Indenture to be used in connection with the issuance of Senior Notes.*
4.3	—	Form of Subordinated Note Indenture to be used in connection with the issuance of Junior Subordinated Notes.
4.4	—	Form of Supplemental Indenture to Subordinated Note Indenture to be used in connection with the issuance of Junior Subordinated Notes.*
4.5	—	Amended and restated Articles of Incorporation of Gulf Power Company 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.)
4.6	—	Form of Articles of Amendment to Charter establishing a series of the Class A Preferred Stock.*
4.7	—	Form of Articles of Amendment to Charter establishing a series of the Preference Stock.*
4.8	—	By-laws of Gulf Power Company 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.)
4.9	—	Form of Senior Note (included in Exhibit 4.2 above).
4.10	—	Form of Junior Subordinated Note (included in Exhibit 4.4 above).
5.1	—	Opinion of Beggs & Lane, a Registered Limited Liability Partnership.
5.2	—	Opinion of Troutman Sanders LLP.
12.1	—	Computation of ratio of earnings to fixed charges.
12.2	—	Computation of ratio of earnings to fixed charges plus preference dividend requirement (pre-income tax basis).
23.1	—	Consent of Deloitte & Touche LLP.
23.2	—	Consent of Beggs & Lane, a Registered Limited Partnership (included in Exhibit 5.1 above).
23.3	—	Consent of Troutman Sanders LLP (included in Exhibit 5.2 above).
24.1	—	Powers of Attorney and Resolution.
25.1	—	Statement of Eligibility under Trust Indenture Act of 1939, as amended, of Wells Fargo Bank, National Association (as successor to The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (Formerly known as The Chase Manhattan Bank))), as Senior Note Indenture Trustee.
25.2	—	Statement of Eligibility under Trust Indenture Act of 1939, as amended, of the Subordinated Note Indenture Trustee.**

Exhibits listed above which have heretofore been filed with the Commission and which were designated as noted above are hereby incorporated herein by reference and made a part hereof with the same effect as if filed herewith.

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* To be subsequently filed or incorporated by reference.

** To be subsequently filed or incorporated by reference or filed separately pursuant to the Trust Indenture Act of 1939, as amended, Section 305(b)(2).

Item 17. ***Undertakings.***

(a) Undertaking related to Rule 415 offering:

The undersigned registrant hereby undertakes:

(1) To file, during any period in which offers or sales are being made, a post-effective amendment to this registration statement:

(i) To include any prospectus required by Section 10(a)(3) of the Securities Act of 1933;

(ii) To reflect in the prospectus any facts or events arising after the effective date of the registration statement (or the most recent post-effective amendment thereof) which, individually or in the aggregate, represent a fundamental change in the information set forth in the registration statement. Notwithstanding the foregoing, any increase or decrease in volume of securities offered (if the total dollar value of securities offered would not exceed that which was registered) and any deviation from the low or high end of the estimated maximum offering range may be reflected in the form of prospectus filed with the Commission pursuant to Rule 424(b) if, in the aggregate, the changes in volume and price represent no more than 20 percent change in the maximum aggregate offering price set forth in the "Calculation of Registration Fee" table in the effective registration statement.

(iii) To include any material information with respect to the plan of distribution not previously disclosed in the registration statement or any material change to such information in the registration statement;

Provided, however, that paragraphs (a)(1)(i), (a)(1)(ii) and (a)(1)(iii) do not apply if the registration statement is on Form S-3 or Form F-3 and the information required to be included in a post-effective amendment by those paragraphs is contained in reports filed with or furnished to the Commission by the registrant pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 that are incorporated by reference in the registration statement, or is contained in a form of prospectus filed pursuant to Rule 424(b) that is part of the registration statement.

(2) That, for the purpose of determining any liability under the Securities Act of 1933, each such post-effective amendment shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial *bona fide* offering thereof.

(3) To remove from registration by means of a post-effective amendment any of the securities being registered which remain unsold at the termination of the offering.

(4) That, for the purpose of determining liability under the Securities Act of 1933 to any purchaser:

(A) Each prospectus filed by the registrant pursuant to Rule 424(b)(3) shall be deemed to be part of the registration statement as of the date the filed prospectus was deemed part of and included in the registration statement; and

(B) Each prospectus required to be filed pursuant to Rule 424(b)(2), (b)(5), or (b)(7) as part of a registration statement in reliance on Rule 430B relating to an offering made pursuant to Rule 415(a)(1)(i), (vii), or (x) for the purpose of providing the information required by section 10(a) of the Securities Act of 1933 shall be deemed to be part of and included in the registration statement as of the earlier of the date such form of prospectus is first used after effectiveness or the date of the first contract of sale of securities in the offering described in the prospectus. As provided in Rule 430B, for liability purposes of the issuer and any person that is at that date an underwriter, such date shall be deemed to be a new effective date of the registration statement relating to the securities in the registration statement to which that prospectus relates, and the offering of such securities at that time shall be deemed to be the initial *bona fide* offering thereof. *Provided, however,* that no statement made in a registration statement or prospectus that is part of the registration statement or made in a document incorporated or deemed incorporated by reference into the registration

statement or prospectus that is part of the registration statement will, as to a purchaser with a time of contract of sale prior to such effective date, supersede or modify any statement that was made in the registration statement or prospectus that was part of the registration statement or made in any such document immediately prior to such effective date.

(5) That, for the purpose of determining liability of the registrant under the Securities Act of 1933 to any purchaser in the initial distribution of the securities:

The undersigned registrant undertakes that in a primary offering of securities of the undersigned registrant pursuant to this registration statement, regardless of the underwriting method used to sell the securities to the purchaser, if the securities are offered or sold to such purchaser by means of any of the following communications, the undersigned registrant will be a seller to the purchaser and will be considered to offer or sell such securities to such purchaser:

(i) Any preliminary prospectus or prospectus of the undersigned registrant relating to the offering required to be filed pursuant to Rule 424;

(ii) Any free writing prospectus relating to the offering prepared by or on behalf of the undersigned registrant or used or referred to by the undersigned registrant;

(iii) The portion of any other free writing prospectus relating to the offering containing material information about the undersigned registrant or its securities provided by or on behalf of the undersigned registrant; and

(iv) Any other communication that is an offer in the offering made by the undersigned registrant to the purchaser.

(b) Undertaking related to filings incorporating subsequent Securities Exchange Act of 1934 documents by reference:

The undersigned registrant hereby undertakes that, for purposes of determining any liability under the Securities Act of 1933, each filing of the registrant's annual report pursuant to Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934 that is incorporated by reference in the registration statement shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial *bona fide* offering thereof.

(c) Undertaking related to acceleration of effectiveness:

Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to directors, officers and controlling persons of the registrant pursuant to the foregoing provisions or otherwise, the registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrant of expenses incurred or paid by a director, officer or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Act and will be governed by the final adjudication of such issue.

(d) The undersigned registrant hereby undertakes to file an application for the purpose of determining the eligibility of the Subordinated Note Indenture Trustee to act under subsection (a) of Section 310 of the Trust Indenture Act (the "Act") in accordance with the rules and regulations prescribed by the Securities and Exchange Commission under Section 305(b)(2) of the Act.

SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, Gulf Power Company certifies that it has reasonable grounds to believe that it meets all of the requirements for filing on Form S-3 and has duly caused this registration statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Atlanta, State of Georgia, on May 17, 2016.

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

Pursuant to the requirements of the Securities Act of 1933, this registration statement has been signed by the following persons in the capacities and on the date indicated.

Signature	Title	Date
S.W. CONNALLY, JR.	Chairman, President, Chief Executive Officer and Director (Principal Executive Officer)	
XIA LIU	Vice President and Chief Financial Officer (Principal Financial Officer)	
JANET J. HODNETT	Comptroller (Principal Accounting Officer)	
ALLAN G. BENSE DEBORAH H. CALDER WILLIAM C. CRAMER, JR. JULIAN B. MACQUEEN J. MORT O'SULLIVAN, III MICHAEL T. REHWINKEL WINSTON E. SCOTT	Directors	

By: /s/ MELISSA K. CAEN
Melissa K. Caen
Attorney-in-fact

May 17, 2016

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) 506-5526	58-0257110
001-31737	**Gulf Power Company** (A Florida Corporation) One Energy Place Pensacola, Florida 32520 (850) 444-5111	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

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 5.83% Series	**Alabama Power Company**
Class A preferred stock, non-cumulative, Par value $25 per share 6 1/8% Series	**Georgia Power Company**
Depositary preferred shares, each representing one-fourth of a share of preferred stock, cumulative, $100 par value 5.25% Series	**Mississippi Power Company**
Senior Notes 1.000% Series 2016A due 2022 1.850% Series 2016B due 2026	**Southern Power Company**

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

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

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 anc 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 I	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.

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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 tc 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

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 I 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.

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 .

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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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

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
Southern Company and Subsidiary Companies 2016 Annual Report

	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				Accumulated Other Comprehensive Income (Loss)	Preferred and Preference Stock of Subsidiaries	Noncontrolling Interests	Total
	Issued	Treasury	Par Value	Paid-In Capital	Treasury	Retained Earnings				
	(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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Southern Company and Subsidiary Companies 2016 Annual Report

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

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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.

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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

NOTES (continued)
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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)*	—	*32*	*(35)*
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.

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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 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

NOTES (continued)
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An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 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

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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

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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)
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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

NOTES (continued)
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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.

NOTES (continued)
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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)
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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)
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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	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)
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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.

NOTES (continued)
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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)
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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	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

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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 furtner 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

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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.

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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

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.

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

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.

NOTES (continued)
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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.

NOTES (continued)
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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.

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Bank Credit Arrangements

At December 31, 2016 , committed credit arrangements with banks were as follows:

Company	Expires 2017	Expires 2018	Expires 2020	Total	Unused	Executable Term Loans One Year	Executable Term Loans Two Years	Expires Within One Year Term Out	Expires Within One Year 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

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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**

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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.

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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.

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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.

NOTES (continued)
Southern Company and Subsidiary Companies 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)**	**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)
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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)
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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.

NOTES (continued)
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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.

NOTES (continued)
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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.

NOTES (continued)
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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

NOTES (continued)
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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)
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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.

NOTES (continued)
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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.

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

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.

NOTES (continued)
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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**

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

14. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

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

Quarter Ended	Operating Revenues	Operating Income	Consolidated Net Income Attributable to Southern Company	Per Common Share				
				Basic Earnings	Diluted Earnings	Dividends	Trading Price Range	
							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.

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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.

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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama 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)*	**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.

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 Fair Value	Maturity	
		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
Alabama Power Company 2016 Annual Report

	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
Alabama Power Company 2016 Annual Report

	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
Alabama Power Company 2016 Annual Report

	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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Alabama Power Company 2016 Annual Report

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)
Alabama 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	$ 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.

NOTES (continued)
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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.

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

NOTES (continued)
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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.

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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 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

NOTES (continued)
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An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 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 .

	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.

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

NOTES (continued)
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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

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	$ 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.

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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.

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.

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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.

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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:

	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.

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- *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 .

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.

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.

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	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.

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 th e final maturity date of February 20, 2044. The proceeds were used to reimburse the Company for Eligible Project Costs relating to the construction of Plant Vogtle Units 3 and 4.

Under the Loan Guarantee Agreement, the Company is subject to customary events of default, as well as cross-defaults to other indebtedness and events of default relating to any failure to make payments under the engineering, procurement, and construction contract, as amended, relating to Plant Vogtle Units 3 and 4 or certain other agreements providing intellectual property rights for Plant Vogtle Units 3 and 4. The Loan Guarantee Agreement also includes events of default specific to the DOE loan guarantee program, including the failure of the Company or Southern Nuclear to comply with requirements of law or DOE loan guarantee program requirements. 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 Fair Value	Maturity	
		Year 1	Years 2&3
		(in millions)	
Level 1	$ —	$ —	$ —
Level 2	36	28	8
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ 36	$ 28	$ 8

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

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to total $2.6 billion for 2017, $2.7 billion for 2018, $2.1 billion for 2019, $1.9 billion for 2020, and $1.7 billion for 2021. These amounts include expenditures of approximately $0.7 billion, $0.5 billion, $0.3 billion, and $0.1 billion for the construction of Plant Vogtle Units 3 and 4 in 2017, 2018, 2019, and 2020, respectively. These amounts also include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these amounts are $0.4 billion , $0.3 billion , $0.1 billion , $0.2 billion , and $0.2 billion for 2017, 2018, 2019, 2020, and 2021, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from new, existing, modified, or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and "– Global Climate Issues" herein for additional information.

The Company also anticipates costs associated with closure and monitoring of ash ponds in accordance with the CCR Rule, which are reflected in the Company's ARO liabilities. These costs, which could change as the Company continues to refine its assumptions underlying the cost estimates and evaluate the method and timing of compliance activities, are estimated to be $0.3 billion for 2017 and $0.2 billion per year for 2018 through 2021. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

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

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

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

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, other purchase commitments, and trusts are

detailed in the contractual obligations table that follows. See Notes 1, 2, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

Contractual obligations at December 31, 2016 were as follows:

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

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

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

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

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

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

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

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

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

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

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

Cautionary Statement Regarding Forward-Looking Statements

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

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

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

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

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

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

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

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

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

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

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

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

Cash and Cash Equivalents at End of Year	**$**	**3**	**$**	67	**$**	24
Supplemental Cash Flow Information:						
Cash paid during the period for —						
Interest (net of $20, $16, and $18 capitalized, respectively)	**$**	**375**	$	353	$	319
Income taxes (net of refunds)		**170**		506		507
Noncash transactions —						
Accrued property additions at year-end		**336**		387		154
Capital lease obligation		—		149		—

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

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

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

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

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

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

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

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

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

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

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2016 , 2015 , and 2014
Georgia Power Company 2016 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in millions)			
Balance at December 31, 2013	9	$ 398	$ 5,633	$ 3,565	$ (5)	$ 9,591
Net income after dividends on preferred and preference stock	—	—	—	1,225	—	1,225
Capital contributions from parent company	—	—	563	—	—	563
Other comprehensive income (loss)	—	—	—	—	(3)	(3)
Cash dividends on common stock	—	—	—	(954)	—	(954)
Other	—	—	—	(1)	—	(1)
Balance at December 31, 2014	9	398	6,196	3,835	(8)	10,421
Net income after dividends on preferred and preference stock	—	—	—	1,260	—	1,260
Capital contributions from parent company	—	—	79	—	—	79
Other comprehensive income (loss)	—	—	—	—	(7)	(7)
Cash dividends on common stock	—	—	—	(1,034)	—	(1,034)
Balance at December 31, 2015	**9**	**398**	**6,275**	**4,061**	**(15)**	**10,719**
Net income after dividends on preferred and preference stock	—	—	—	**1,330**	—	**1,330**
Capital contributions from parent company	—	—	**610**	—	—	**610**
Other comprehensive income (loss)	—	—	—	—	**2**	**2**
Cash dividends on common stock	—	—	—	**(1,305)**	—	**(1,305)**
Balance at December 31, 2016	**9**	**$ 398**	**$ 6,885**	**$ 4,086**	**$ (13)**	**$ 11,356**

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

NOTES TO FINANCIAL STATEMENTS
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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.

NOTES (continued)
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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.

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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.

NOTES (continued)
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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

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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.

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2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). On December 19, 2016, the Company voluntarily contributed $287 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2017 . The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the Georgia PSC and the FERC. For the year ending December 31, 2017 , no other postretirement trust contributions are expected.

Actuarial Assumptions

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

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

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

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

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

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

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

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

Pension Plans

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

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

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

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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

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

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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.

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

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

Employee Savings Plan

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

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

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

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

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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

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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.

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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.

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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.

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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

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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.

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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)
Georgia Power Company 2016 Annual Report

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.

NOTES (continued)
Georgia Power Company 2016 Annual Report

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.

NOTES (continued)
Georgia Power Company 2016 Annual Report

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.

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.

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.

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.

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.

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 Fair Value	Maturity		
		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.

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
Gulf Power Company 2016 Annual Report

	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
Gulf Power Company 2016 Annual Report

	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
Gulf Power Company 2016 Annual Report

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.

NOTES (continued)
Gulf Power Company 2016 Annual Report

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.

NOTES (continued)
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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.

NOTES (continued)
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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.

NOTES (continued)
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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	—	—

NOTES (continued)
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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	

NOTES (continued)
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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

NOTES (continued)
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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

NOTES (continued)
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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.

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	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.

	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	280
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.

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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.

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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 .

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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.

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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.

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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)**	**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.

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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 .

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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.

NOTES (continued)
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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.

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 Fair Value	Maturity	
		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)
Mississippi Power Company 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	$ 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
Mississippi Power Company 2016 Annual Report

	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
Mississippi Power Company 2016 Annual Report

	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
Mississippi Power Company 2016 Annual Report

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
Mississippi Power Company 2016 Annual Report

	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
Mississippi Power Company 2016 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total
				(in millions)		
Balance at December 31, 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.

NOTES TO FINANCIAL STATEMENTS
Mississippi Power Company 2016 Annual Report

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Mississippi Power Company 2016 Annual Report

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.

NOTES (continued)
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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.

NOTES (continued)
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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 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.

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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.

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

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.

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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.

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.

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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. In 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.

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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.

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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

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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

NOTES (continued)
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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.

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Effective Tax Rate

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

	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.

NOTES (continued)
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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 .

NOTES (continued)
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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	3,643	$ 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.

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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.

NOTES (continued)
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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.

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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)**	**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.

NOTES (continued)
Mississippi Power Company 2016 Annual Report

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.

NOTES (continued)
Mississippi Power Company 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 (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.

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.

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 .

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.

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.

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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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.

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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.

NOTES (continued)
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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)
Southern Power Company and Subsidiary Companies 2016 Annual Report

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

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.

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 .

NOTES (continued)
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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.

NOTES (continued)
Southern Power Company and Subsidiary Companies 2016 Annual Report

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 .

NOTES (continued)
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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)
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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)
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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
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	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
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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, 2016	January 1, 2016 through June 30, 2016	Years Ended December 31, 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.

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	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	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.

	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		Physical Transportation Transactions – Expected Net Operating Gains (Losses) [b]
	Total storage (WACOG $2.76)	Expected net operating gains [a]	
	(in mmBtu in millions)	*(in millions)*	*(in millions)*
2017	**67.2**	**$ 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.

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

	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.

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.

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

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.

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:

Company	Expires		Total	Unused	Expires Within One Year	
	2017	2018			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 .

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:

	Total Fair Value	Fair Value Measurements Successor – December 31, 2016 Maturity		
		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 2016	Predecessor 2015	**Successor 2016**	Predecessor 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

Assets	Successor December 31, 2016 (in millions)	Predecessor December 31, 2015 (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				Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Issued	Treasury	Par Value	Paid-In Capital	Treasury	Retained Earnings			
	(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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Southern Company Gas and Subsidiary Companies 2016 Annual Report

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.

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.

NOTES (continued)
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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.

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)
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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)**

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)
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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 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)
Southern Company Gas and Subsidiary Companies 2016 Annual Report

	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.

	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.

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.

NOTES (continued)
Southern Company Gas and Subsidiary Companies 2016 Annual Report

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

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.

NOTES (continued)
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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.

NOTES (continued)
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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.

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.

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	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)
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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.

14. CAPITALIZATION

The capitalization for the years ended December 31, 2016 and 2015 are as follows:

	Successor 2016	Predecessor 2015	Successor 2016	Predecessor 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 Director	2015	420,758	—	553,946	—	391,000	160,338	30,485	1,556,527
	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			Grant Date Fair Value of Stock and Option Awards
Name (a)	Grant Date (b)	Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	($) (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.

T he following chart describes the treatment of different pay and benefit elements in connection with the Traditional Termination Events as described above.

Program	Retirement/ Retirement-Eligible	Lay Off (Involuntary Termination Not For Cause)	Resignation	Death or Disability	Involuntary Termination (For Cause)
Pension Benefits Plans	Benefits payable as described in the notes following the Pension Benefits table.	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.

	Number of Equity Awards with Accelerated Vesting (#)		Total Number of Equity Awards Following Accelerated Vesting (#)		Total Payable in Cash without Conversion of Equity
Name	Stock Options	Performance Shares	Stock Options	Performance Shares	Awards ($)
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

INDEX TO FINANCIAL STATEMENT SCHEDULES

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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)

Description	Balance at Beginning of Period	Additions			Deductions (Note)	Balance at End of Period
		Charged to Income	Charged to Other Accounts	Acquisitions		
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		Deductions (Note)	Balance at End of Period
		Charged to Income	Charged to Other Accounts		
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		Deductions (Note)	Balance at End of Period
		Charged to Income	Charged to Other Accounts		
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: Charged to Income	Additions: Charged to Other Accounts	Deductions (Note)	Balance at End of Period
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		Deductions (Note)	Balance at End of Period
		Charged to Income	Charged to Other Accounts		
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)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: 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

Space Above this Line Reserved for Recorder's Use Only

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

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		

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

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.

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

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

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.

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/John D. Johns
John D. Johns

/s/Jon A. Boscia
Jon A. Boscia

/s/Dale E. Klein
Dale E. Klein

/s/Henry A. Clark III
Henry A. Clark III

/s/William G. Smith, Jr.
William G. Smith, Jr.

/s/Thomas A. Fanning
Thomas A. Fanning

/s/Steven R. Specker
Steven R. Specker

/s/David J. Grain
David J. Grain

/s/Larry D. Thompson
Larry D. Thompson

/s/Veronica M. Hagen
Veronica M. Hagen

/s/E. Jenner Wood III
E. Jenner Wood III

/s/Warren A. Hood, Jr.
Warren A. Hood, Jr.

/s/Art P. Beattie
Art P. Beattie

/s/Linda P. Hudson
Linda P. Hudson

/s/Ann P. Daiss
Ann P. Daiss

/s/Donald M. James
Donald M. James

Extract from minutes of meeting of the board of directors of The Southern Company.

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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.

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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

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.

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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.

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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 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.

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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.

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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.

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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.

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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.

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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.

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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 are authorized to give their several powers of attorney to Elliott L. Spencer and Melissa K. Caen.

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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/Kimberly S. Greene
Kimberly S. Greene

/s/Thomas D. Bell, Jr.
Thomas D. Bell, Jr.

/s/John E. Rau
John E. Rau

/s/Charles R. Crisp
Charles R. Crisp

/s/James A. Rubright
James A. Rubright

/s/Andrew W. Evans
Andrew W. Evans

/s/Elizabeth W. Reese
Elizabeth W. Reese

/s/Brenda J. Gaines
Brenda J. Gaines

/s/Grace A. Kolvereid
Grace A. Kolvereid

Extract from minutes of meeting of the board of directors of Southern Company Gas.

- - - - - - - - - -

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

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.

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.