DOCKET NO. 150195-EI

FILED SEP 03, 2015
DOCUMENT NO. 05522-15
FPSC - COMMISSION CLERK

Robert L. McGee, Jr.
Regulatory & Pricing Manager

One Energy Place
Pensacola, Florida 32520-0780

Tel 850.444.6530
Fax 850.444.6026
RLMCGEE@southernco.com

GULF POWER
A SOUTHERN COMPANY

September 2, 2015

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

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

Dear Ms. Stauffer:

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

Jeffrey A. Stone
Beggs & Lane
P.O. Box 12950
Pensacola, FL 32591-2950

Susan D. Ritenour
Gulf Power Company
One Energy Place
Pensacola, FL 32520-07860

Sincerely,

Robert L. McGee, Jr.
Regulatory and Pricing Manager

md

Enclosures

Cc w/encl: Beggs & Lane
Jeffrey A. Stone, Esq.

COM
AFD 4
APA
ECO
ENG
GCL 1
IDM
TEL
CLK

bc w/encl: S. Boyett
M. Caen
K. Harris
S. Jordan
X. Liu (electronic)
J. Mason
R. McGee
S. Ritenour
A. Williams

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Gulf Power Company's application for authority to issue and sell securities and to receive common equity contributions	)	Docket No. 15 -EI Filed: September 2, 2015

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

Gulf Power Company ("Gulf Power", "Gulf", or "the Company"), pursuant to Chapter 25-8, Florida Administrative Code, and Section 366.04, Florida Statutes, hereby files this application for authority to issue and sell securities and to receive common equity contributions during the twelve months ending December 31, 2016. In support of this application, the Company states:

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

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

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

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

Jeffrey A. Stone Beggs & Lane P. O. Box 12950 Pensacola, FL 32591-2950	Susan D. Ritenour Gulf Power Company One Energy Place Pensacola, FL 32520-0786

(4) Capital Stock and Funded Debt of the Company at June 30, 2015, was:

CAPITAL STOCK

		Preference Stock $100 Par Value	Class A Preferred Stock $25 Par Value	Preferred Stock $100 Par Value	Common Stock Without Par Value
(a)	Brief description:				
(b)	Shares authorized:	10,000,000	10,000,000	10,000,000	20,000,000
(c)	Shares outstanding:				
	6.00% Series	550,000			
	6.45% Series	450,000			
	5.60% Series	500,000			
(d)	The amount held as reacquired securities:	None	None	None	None
(e)	The amount pledged by applicant:	None	None	None	None
(f)	The amount owned by affiliated corporations:	None	None	None	5,642,717
(g)	The amount held in any fund:	None	None	None	None

FUNDED DEBT

		Long-Term Notes Payable $	PCBs $
(a)	Brief description:		
(b)	Amount authorized:	Not Limited	Not Limited
(c)	Amount outstanding (000):		
	2.10% Series due 2022		37,000
	Daily Rate Series due 2022		3,930
	1.550% Series due 2023		32,550
	2.00% Series due 2037		42,000
	1.40% Series due 2039		65,000
	Daily Rate Series due 2039		65,400
	.550% Series due 2042		13,000
	4.450% Series due 2044		29,075
	1.70% Series due 2049		21,000
	5.30% Sr. Notes due 2016	110,000	
	5.90% Sr. Notes due 2017	85,000	
	4.75% Sr. Notes due 2020	175,000	
	3.10% Sr. Notes due 2022	100,000	
	5.65% Sr. Notes due 2035	60,000	
	5.10% Sr. Notes due 2040	125,000	
	5.00% Sr. Notes due 2043	90,000	
	4.55% Sr. Notes due 2044	200,000	
	5.75% Sr. Notes due 2051	125,000	
(d)	Amount held as reacquired securities:	None	None
(e)	Amount pledged:	None	None
(f)	Amount owned by affiliated corporations:	None	None
(g)	Amount held in any fund:	None	None

(5) Statement of Proposed Transactions:

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

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

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

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

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

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

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

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

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

The Statement of Sources of Funds for Gross Property Additions Forecast for the Year Ending December 31, 2016, is included as Exhibit B (1).

The actual capital structure at June 30, 2015, is as follows:

Component	Amount (000)	Ratio
Common Equity	$1,340,235	44.47 %
Preference Stock	150,000	4.98 %
Long-Term Debt	1,369,886	45.45 %
Short-Term Debt	153,970	5.11 %
TOTAL	$3,014,091	100.00 %

Pretax Coverage Ratio (Excluding AFUDC): 4.91

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

(1) The interest rate for comparable A rated 30 year Senior Notes was 4.38% as of August 28, 2015.

(2) The dividend rate for comparable BBB+ rated preference stock was 5.73% as of August 21, 2015.

(3) The prime interest rate, or its equivalent, for JPMorgan Chase Bank, N.A. was 3.25% as of August 28, 2015.

(4) The interest rate in effect for 90-day direct issue commercial paper as published in the Federal Reserve Statistical Release (Form H.15) was 0.19% as of August 25, 2015.

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

(6) Purpose of Issues:

The net proceeds to be received from these additional funds will be added to the Company's general funds and will be used for working capital requirements and for other general business purposes, including the financing of the Company's construction program.

(a) The Company is engaged in a continuous construction program to accommodate existing and estimated future loads of the system. Total construction additions during 2016 are estimated to cost $186,216,000 and are expected to be apportioned as shown in Exhibit B (1).

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

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

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

(7) The Company submits that the proposed additional funds are for lawful objects within the corporate purposes of the Company and compatible with the public

interest and are reasonably necessary or appropriate for such purposes. The facts relied upon by the Company in support of such allegations are set forth in paragraph (6) hereof.

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

Beggs & Lane
501 Commendencia Street
P. O. Box 12950
Pensacola, FL 32591-2950

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

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

(10) Southern, a Delaware corporation, owns 5,642,717 shares of the Company's common stock, without par value, representing 100% of the voting stock outstanding. Southern is also the parent company of three other traditional operating companies and certain other companies including: Southern LINC Wireless; Southern Company Services; Southern Nuclear; Southern Holdings; and other direct and indirect subsidiaries.

WHEREFORE, the Company respectfully requests an order authorizing it to issue and sell securities and to receive common equity contributions from Southern during the twelve months ending December 31, 2016.

DATED: September 2, 2015

GULF POWER COMPANY

BY: _____
Susan D. Ritenour
Secretary and Treasurer

ATTEST:

_____
Sharon A. Jordan
Assistant Secretary

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Susan D. Ritenour, being duly sworn, deposes and says that she is the Secretary and Treasurer of Gulf Power Company, that she has read the foregoing petition and knows the contents thereof, and that the facts therein are true and correct to the best of her knowledge, information and belief.

Susan D. Ritenour

STATE OF FLORIDA
COUNTY OF ESCAMBIA

The foregoing instrument was acknowledged before me this 2nd day of September, 2015, by Susan D. Ritenour of Gulf Power Company, a Florida corporation, on behalf of the corporation. She is personally known to me and did take an oath.

NOTARY PUBLIC

CANDACE KLINGLESMITH
Notary Public - State of Florida
Commission # FF 206141
My Comm. Expires May 18, 2019
Bonded through National Notary Assn.

REQUIRED EXHIBITS

Exhibit A (6)(i) -	The financial statements and accompanying footnotes as they appear in the Company's Annual Report on Form 10-K for the year ended December 31, 2014, and filed with the SEC in file no. 1-31737 on March 2, 2015.
Exhibit A (6)(ii) -	The financial statements and accompanying footnotes as they appear in the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015, and filed with the SEC in file no. 1-31737 on August 5, 2015.
Exhibit B (1) -	Statement of Sources and Uses of Funds for the twelve months ended December 31, 2016 and the Construction Budget for Gross Property Additions.

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

FORM 10-K

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

For the Fiscal Year Ended December 31, 2014

OR

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

For the Transition Period from to

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-3526	**The Southern Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-0690070
1-3164	**Alabama Power Company** (An Alabama Corporation) 600 North 18th Street Birmingham, Alabama 35291 (205) 257-1000	63-0004250
1-6468	**Georgia Power Company** (A Georgia Corporation) 241 Ralph McGill Boulevard, N.E. Atlanta, Georgia 30308 (404) 506-6526	58-0257110
001-31737	**Gulf Power Company** (A Florida Corporation) One Energy Place Pensacola, Florida 32520 (850) 444-6111	59-0276810
001-11229	**Mississippi Power Company** (A Mississippi Corporation) 2992 West Beach Boulevard Gulfport, Mississippi 39501 (228) 864-1211	64-0205820
333-98553	**Southern Power Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-2598670

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**
Class A preferred, cumulative, $25 stated capital 5.20% Series 5.83% Series 5.30% Series	**Alabama Power Company**
Class A Preferred Stock, non-cumulative, Par value $25 per share 6 1/8% Series	**Georgia Power Company**
Senior Notes 5.75% Series 2011A	**Gulf 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**

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, 2014.

[This page intentionally left blank]

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

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	

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, 2014: $40.7 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, 2015
The Southern Company	Par Value $5 Per Share	909,877,898
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	5,642,717
Mississippi Power Company	Without Par Value	1,121,000
Southern Power Company	Par Value $0.01 Per Share	1,000

Documents incorporated by reference: specified portions of The Southern Company's Definitive Proxy Statement on Schedule 14A relating to the 2015 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 2015 Annual Meetings of Shareholders are incorporated by reference into PART III.

Southern Power Company 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, and Southern Power Company. 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.

Table of Contents

		Page
	PART I	
Item 1	Business	I-1
	The Southern Company System	I-2
	Construction Programs	I-6
	Financing Programs	I-7
	Fuel Supply	I-7
	Territory Served by the Traditional Operating Companies and Southern Power	I-8
	Competition	I-10
	Seasonality	I-11
	Regulation	I-11
	Rate Matters	I-13
	Employee Relations	I-16
Item 1A	Risk Factors	I-17
Item 1B	Unresolved Staff Comments	I-32
Item 2	Properties	I-33
Item 3	Legal Proceedings	I-40
Item 4	Mine Safety Disclosures	I-40
	Executive Officers of Southern Company	I-41
	Executive Officers of Alabama Power	I-43
	Executive Officers of Georgia Power	I-44
	Executive Officers of Mississippi Power	I-45
	PART II	
Item 5	Market for Registrants' Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	II-1
Item 6	Selected Financial Data	II-2
Item 7	Management's Discussion and Analysis of Financial Condition and Results of Operations	II-2
Item 7A	Quantitative and Qualitative Disclosures about Market Risk	II-3
Item 8	Financial Statements and Supplementary Data	II-4
Item 9	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	II-6
Item 9A	Controls and Procedures	II-6
Item 9B	Other Information	II-6
	PART III	
Item 10	Directors, Executive Officers and Corporate Governance	III-1
Item 11	Executive Compensation	III-4
Item 12	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	III-41
Item 13	Certain Relationships and Related Transactions, and Director Independence	III-42
Item 14	Principal Accountant Fees and Services	III-43
	PART IV	
Item 15	Exhibits and Financial Statement Schedules	IV-1
	Signatures	IV-2

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
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
Clean Air Act	Clean Air Act Amendments of 1990
CCR	Coal combustion residuals
CO_2	Carbon dioxide
Code	Internal Revenue Code of 1986, as amended
CPCN	Certificate of Public Convenience and Necessity
CWIP	Construction Work in Progress
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, Inc.
EPA	U.S. Environmental Protection Agency
EMC	Electric membership corporation
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
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ITC	Investment tax credit
Kemper IGCC	IGCC facility under construction in Kemper County, Mississippi
KUA	Kissimmee Utility Authority
KW	Kilowatt
KWH	Kilowatt-hour
MATS rule	Mercury and Air Toxics Standards rule
MEAG Power	Municipal Electric Authority of Georgia
Mississippi Power	Mississippi Power Company
MW	Megawatt
NRC	U.S. Nuclear Regulatory Commission
NYSE	New York Stock Exchange
OPC	Oglethorpe Power Corporation
OUC	Orlando Utilities Commission
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 operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PowerSouth	PowerSouth Energy Cooperative
PPA	Power Purchase Agreement

DEFINITIONS
(continued)

Term	Meaning
PSC	Public Service Commission
registrants	Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power Company
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
Southern Company	The Southern Company
Southern Company system	Southern Company, the traditional operating companies, Southern Power, SEGCO, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
Southern Holdings	Southern Company Holdings, Inc.
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
TIPA	Tax Increase Prevention Act of 2014
traditional operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power

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 retail rates, the strategic goals for the wholesale business, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, completion dates of acquisitions and construction projects, filings with state and federal regulatory authorities, impact of the TIPA, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, coal combustion residuals, and emissions of sulfur, nitrogen, CO_2, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, and Internal Revenue Service and state tax audits;
- 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, 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, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction 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 operational and environmental performance standards, including any PSC requirements 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 Southern Company's employee and retiree benefit plans and the Southern Company system's 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;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions and related legal proceedings involving the commercial parties;
- actions related to cost recovery for the Kemper IGCC, including actions relating to proposed securitization, Mississippi PSC approval of a rate recovery plan, including the ability to complete the proposed sale of an interest in the Kemper IGCC to SMEPA, the ability to utilize bonus depreciation, which currently requires that assets be placed in service in 2015, and satisfaction of requirements to utilize ITCs and grants;

- Mississippi PSC review of the prudence of Kemper IGCC costs;
- the ultimate outcome and impact of the February 2015 decision of the Mississippi Supreme Court and any further legal or regulatory proceedings regarding any settlement agreement between Mississippi Power and the Mississippi PSC, the March 2013 rate order regarding retail rate increases, or the Baseload Act;
- the ability to successfully operate the electric utilities' generating, transmission, and distribution 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, or financial risks;
- 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 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 or 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 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 and its subsidiaries to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Southern Company system'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 filed by the registrants from time to time with the SEC.

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

[This page intentionally left blank]

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 operating companies supply electric service in the states of Alabama, Georgia, Florida, and Mississippi. More particular information relating to each of the traditional 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 and was admitted to do business in the States of Alabama, Florida, and Georgia on January 10, 2001, in the State of Mississippi on January 30, 2001, in the State of North Carolina on February 19, 2007, and in the State of South Carolina on March 31, 2009. Certain of Southern Power Company's subsidiaries are also admitted to do business in the States of California, Nevada, New Mexico, and Texas.

Southern Company also owns all of the outstanding common stock or membership interests of SouthernLINC Wireless, Southern Nuclear, SCS, Southern Holdings, and other direct and indirect subsidiaries. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and markets these services to the public and also provides wholesale fiber optic solutions to telecommunication providers in the Southeast. Southern Nuclear operates and provides services to Alabama Power's and Georgia Power's nuclear plants and is currently developing Plant Vogtle Units 3 and 4, which are co-owned by Georgia Power. SCS is the Southern Company system service company providing, at cost, specialized services to Southern Company and its subsidiary companies. Southern Holdings is an intermediate holding subsidiary, primarily for Southern Company's investments in leveraged leases.

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 1,019,680 KWs 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.

Southern Company's segment information is included in Note 12 to the financial statements of Southern Company 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 Operating Companies

The traditional 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 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 operating companies and SEGCO. For information on the State of Georgia's integrated transmission system, see "Territory Served by the Traditional 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 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, Inc., 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 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 operating companies are represented on the National Electric Reliability Council.

The utility assets of the traditional 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 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 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 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 Company, each traditional operating company, Southern Power Company, Southern Nuclear, SEGCO, and other subsidiaries have contracted with SCS 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 communications, and other services with respect to business and operations, construction management, and power pool transactions. Southern Power Company and SouthernLINC Wireless have also secured from the traditional operating companies certain services which are furnished at cost and, in the case of Southern Power Company, which are subject to 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 Company is an electric wholesale generation subsidiary with market-based rate authority from the FERC. 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 continually seeks opportunities to execute its strategy to create value through various transactions, including acquisitions and sales of assets, construction of new power plants, and entry into PPAs primarily with investor owned utilities, IPPs, municipalities, and electric cooperatives. Southern Power Company's business activities are not subject to traditional state regulation like the traditional operating companies but 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 acquisition and value creation strategy and to construct generating facilities. 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 registrant. 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.

In April 2013, Southern Power and Turner Renewable Energy, LLC (TRE), through Southern Turner Renewable Energy, LLC (STR), a jointly-owned subsidiary owned 90% by Southern Power, acquired all of the outstanding membership interests of Campo Verde Solar, LLC (Campo Verde). Campo Verde constructed and owns an approximately 139-MW solar photovoltaic facility in Southern California. The solar facility began commercial operation in October 2013 and the entire output of the plant is contracted under a 20-year PPA with San Diego Gas & Electric Company (SDG&E), a subsidiary of Sempra Energy.

Southern Power and TRE, through STR, acquired all of the outstanding membership interests of Adobe Solar, LLC (Adobe) and Macho Springs Solar, LLC (Macho Springs) on April 17, 2014 and May 22, 2014, respectively. The Adobe and Macho Springs solar facilities began commercial operation in May 2014 with the approximate 20-MW Adobe solar photovoltaic facility serving a 20-year PPA with Southern California Edison Company and the approximate 50-MW Macho Springs solar photovoltaic facility serving a 20-year PPA with El Paso Electric Company.

On October 22, 2014, Southern Power, through its subsidiaries Southern Renewable Partnerships, LLC and SG2 Holdings, LLC (SG2 Holdings), acquired all of the outstanding membership interests of SG2 Imperial Valley, LLC (Imperial Valley). Southern Power owns 100% of the class A membership interests of SG2 Holdings and is entitled to 51% of all cash distributions from SG2 Holdings, and First Solar, Inc. indirectly owns 100% of the class B membership interests of SG2 Holdings and is entitled to 49% of all cash distributions from SG2 Holdings. In addition, Southern Power is entitled to substantially all of the federal tax benefits with respect to the transaction. Imperial Valley constructed and owns an approximately 150-MW solar photovoltaic facility in Southern California. The solar facility began commercial operation on November 26, 2014, and the entire output of the plant is contracted under a 25-year PPA with SDG&E.

In December 2014, Southern Power announced that it will build an approximately 131-MW solar photovoltaic facility in Taylor County, Georgia. Construction of the facility is expected to begin in September 2015. Commercial operation is scheduled to begin in the fourth quarter 2016, and the entire output of the facility is contracted under separate 25-year PPAs with Cobb EMC, Flint EMC, and Sawnee EMC.

On February 19, 2015, Southern Power acquired all of the outstanding membership interests of Decatur Parkway Solar Project, LLC and Decatur County Solar Project, LLC from TradeWind Energy, Inc. as part of Southern Power's plan to build two solar photovoltaic facilities, the Decatur Parkway Solar Project and the Decatur County Solar Project. These two projects, approximately 80 MWs and 19 MWs, respectively, will be constructed on separate sites in Decatur County, Georgia. The construction of the Decatur Parkway Solar Project commenced in February 2015 while the construction of the Decatur County Solar Project is expected to commence in June 2015. Both projects are expected to begin commercial operation in late 2015. The entire output of the Decatur Parkway Solar Project is contracted under a 25-year PPA with Georgia Power and the entire output of the Decatur Country Solar Project is contracted under a 20-year PPA with Georgia Power. The total estimated cost of the facilities is expected to be between $200 million and $220 million, which includes the acquisition price for all of the outstanding membership interests of Decatur Parkway Solar Project, LLC and Decatur County Solar Project, LLC from Tradewind Energy, Inc.

On February 24, 2015, Southern Power, through its wholly owned subsidiary SRE, entered into a purchase agreement with Kay Wind Holdings, LLC, a wholly-owned subsidiary of Apex Clean Energy Holdings, LLC, the developer of the project, to acquire all of the outstanding membership interests of Kay Wind, LLC (Kay Wind) for approximately $492 million, with potential purchase price adjustments based on performance testing. Kay Wind is constructing an approximately 299 MW wind facility in Kay County, Oklahoma. The wind facility is expected to begin commercial operation in late 2015, and the entire output of the facility is contracted under separate 20-year PPAs with Westar Energy, Inc. and Grand River Dam Authority. The acquisition is expected to close in the fourth quarter 2015 subject to Kay Wind achieving certain financing, construction, and project milestones, and various customary conditions to closing.

See Note 2 to the financial statements of Southern Power in Item 8 herein for additional information regarding Southern Power's acquisitions.

As of December 31, 2014, Southern Power had 9,074 MWs of nameplate capacity in commercial operation, after taking into consideration its equity ownership percentage of the solar facilities. Taking into account the PPAs and capacity from the Taylor County and Decatur County solar projects, as well as the acquisition of Kay Wind, all as discussed above, Southern Power had an average of 77% of its available capacity covered for the next five years (2015 through 2019) and an average of 70% of its available capacity covered for the next 10 years (2015 through 2024).

Southern Power's natural gas and biomass sales are primarily through long-term PPAs. Southern Power's natural gas PPAs 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 solar sales are through long-term PPAs. Each of Southern Power's solar PPAs is a customer purchase from a dedicated solar facility where the customer purchases the entire energy output of the facility.

The following tables set forth Southern Power's existing PPAs as of December 31, 2014:

Block Sales PPAs

Facility/Source	Counterparty	MWs	Contract Term
Addison Unit 1	MEAG Power	150	through April 2029
Addison Units 2 and 4	Georgia Power	296	Jan. 2015 – May 2030
Addison Unit 3	Georgia Energy Cooperative	150	through May 2030
Cleveland County Unit 1	NCEMC(1)	45-180	through December 2036
Cleveland County Unit 2	NCEMC(1)	180	through December 2036
Cleveland County Unit 3	NCMPA1(2)	180	through December 2031
Dahlberg Units 1, 3 and 5	Cobb EMC	225	Jan. 2016 – Dec. 2022
Dahlberg Units 2, 6, 8 and 10	Georgia Power	298	through May 2025
Dahlberg Unit 4	Georgia Power	75	Jan. 2015 – May 2030
Franklin Unit 1	Florida Power & Light Co.	190	through December 2015
Franklin Unit 1	Duke Energy Florida, Inc.	350	through May 2016
Franklin Unit 1	Duke Energy Florida, Inc.	434	June 2016 – May 2021
Franklin Unit 2	Morgan Stanley Capital Group	250	Jan. 2016 – Dec. 2025
Franklin Unit 2	Jackson EMC	60-65	Jan. 2016 – Dec. 2035
Franklin Unit 2	GreyStone Power Corporation	35-40	Jan. 2016 – Dec. 2035
Franklin Unit 2	Cobb EMC	100	Jan. 2016 – Dec. 2022
Franklin Unit 3	Constellation Energy	628	through December 2015
Harris Unit 1	Florida Power & Light Co.	600	through December 2015
Harris Unit 1	Georgia Power(3)	638	June 2015 – May 2030
Harris Unit 2	Georgia Power	636	through May 2019
Nacogdoches	City of Austin, Texas	100	through May 2032
NCEMC PPA(4)	EnergyUnited	100	through December 2021
Oleander Unit 1	Tampa Electric Company	155	through December 2015
Oleander Units 2, 3 and 4	Seminole Electric Cooperative	465	through May 2021
Oleander Unit 5	FMPA	160	through December 2027
Rowan CT Unit 1	NCMPA1(2)	100-150	through December 2030
Rowan CT Unit 3	EnergyUnited	113	Jan. 2015 – December 2023
Rowan CC Unit 4	NCMPA1(2)	50	through December 2015
Rowan CC Unit 4	EnergyUnited	0-274	through December 2025
Rowan CC Unit 4	Duke Energy Progress, Inc.	150	through December 2019
Rowan CC Unit 4	PJM Auction(5)	200	June 2016 – May 2017
Stanton Unit A	OUC	341	through September 2033
Stanton Unit A	FMPA	85	through September 2033
Wansley Unit 6	Georgia Power	568	through May 2017

(1) North Carolina Electric Membership Corporation (NCEMC)

(2) North Carolina Municipal Power Agency (NCMPA)

(3) Georgia Power will be served by Plant Franklin Unit 2 from June 2015 through December 2015.

(4) Represents sale of power purchased from NCEMC under a PPA.

(5) Pennsylvania, Jersey, Maryland Power Pool

Requirements Services PPAs

Counterparty	MWs		Contract Term
Nine Georgia EMCs	239-358	(1)	through December 2024
Sawnee EMC	117-422	(1)	through December 2027
Cobb EMC	26-210	(1)	through December 2015
Cobb EMC	26-210	(1)	Jan. 2016 - Dec. 2025
Flint EMC	131-210	(1)	through December 2024
City of Dalton, Georgia	—	(1)	through December 2017
EnergyUnited	99-236	(1)	through December 2025
City of Seneca, South Carolina	30		through June 2015

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

Solar PPAs

Facility	Counterparty	MWs(1)	Contract Term
Adobe(2)	Southern California Edison Company	20	through April 2034
Apex(2)	Nevada Power Company	20	through November 2037
Campo Verde(2)	San Diego Gas & Electric Company	139	through October 2033
Cimarron(2)	Tri-State Generation and Transmission Association, Inc.	30	through November 2035
Granville(2)	Duke Energy Progress, Inc.	2.5	through November 2032
Imperial Valley(3)	SDG&E	150	through October 2039
Macho Springs(2)	El Paso Energy	50	through April 2034
Spectrum(2)	Nevada Power Company	30	through December 2038
Taylor County	Cobb EMC	101	fourth quarter 2016 - 2041
Taylor County	Flint EMC	15	fourth quarter 2016 - 2041
Taylor County	Sawnee EMC	15	fourth quarter 2016 - 2041

(1) MWs shown are for 100% of the PPA, which is based on the demonstrated capacity of the facility.

(2) Southern Power's equity interest in these facilities is 90%.

(3) Southern Power's equity interest in this facility is 51%.

Purchased Power

Facility/Source	Counterparty	MWs	Contract Term
Sandersville	AL Sandersville Holdings, LLC	280	through December 2015
NCEMC	NCEMC	100	through December 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, 2014, Southern Power derived approximately 10.1% of its revenues from sales to Florida Power & Light Company, approximately 9.7% of its revenues from sales to Georgia Power, and approximately 9.1% of its revenues from sales to Duke Energy Corporation.

Other Businesses

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

SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public. SouthernLINC Wireless 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. SouthernLINC Wireless 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 2015 through 2017, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company, each traditional operating company, and Southern Power 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. In 2015, the construction program is expected to be apportioned approximately as follows:

	Southern Company system *	Alabama Power	Georgia Power	Gulf Power	Mississippi Power
			(in millions)		
New Generation	$ 1,295	$ —	$ 494	$ —	$ 801
Environmental Compliance**	1,035	420	347	127	94
Generation Maintenance	958	395	471	46	29
Transmission	641	180	396	24	40
Distribution	786	312	384	48	41
Nuclear Fuel	277	125	152	—	—
General Plant	277	103	145	18	11
	5,269	1,535	2,389	263	1,016
Southern Power***	1,395	—	—	—	—
Other subsidiaries	64	—	—	—	—
Total	$ 6,728	$ 1,535	$ 2,389	$ 263	$ 1,016

* These amounts include the amounts for the traditional operating companies (as detailed in the table above) as well as the amounts for Southern Power and the other subsidiaries. See "Other Businesses" herein for additional information.

** Reflects cost estimates for environmental regulations. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. 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 operating company in Item 7 herein for additional information.

*** Includes approximately $1.3 billion for potential acquisitions and/or construction of new generating facilities.

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 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; 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. 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 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. 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, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction 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).

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. See Note 3 to the financial statements of Southern Company and Georgia Power under "Retail 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.

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

The traditional 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 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 2012 through 2014.

The traditional operating companies have agreements in place from which they expect to receive substantially all of their coal burn requirements in 2015. These agreements have terms ranging between one and six years. In 2014, the weighted average sulfur content of all coal burned by the traditional operating companies was 0.96% sulfur. This sulfur level, along with banked and purchased sulfur dioxide allowances, allowed the traditional operating companies to remain within limits set by Phase I of the Cross-State Air Pollution Rule (CSAPR) under the Clean Air Act. In 2014, 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 operating companies' fuel mix will be monitored to help ensure that the traditional operating companies remain in compliance with applicable laws and regulations. Additionally, Southern Company and the traditional 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 operating company, and Southern Power in Item 7 herein for additional information on environmental matters.

SCS, acting on behalf of the traditional operating companies and Southern Power Company, has agreements in place for the natural gas burn requirements of the Southern Company system. For 2015, SCS has contracted for 446 billion cubic feet 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 numerous contracts covering a portion of their nuclear fuel needs for uranium, conversion services, enrichment services, and fuel fabrication. These contracts have varying expiration dates and most of them are for less than 10 years. Management believes sufficient capacity for nuclear fuel supplies and processing exists to preclude the impairment of normal operations of the Southern Company system's nuclear generating units.

Changes in fuel prices to the traditional 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) 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.

Territory Served by the Traditional Operating Companies and Southern Power

The territory in which the traditional 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 operating companies. As of December 31, 2014, the territory had an area of approximately 120,000 square miles and an estimated population of approximately 16 million. Southern Power sells electricity at market-based rates in the wholesale market primarily to investor-owned utilities, IPPs, municipalities, and electric cooperatives.

Alabama Power is engaged, within the State of Alabama, in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity, 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 Alabama Municipal Electric Authority, 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 and purchase of electricity and the transmission, distribution, and sale of such electricity 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.

Gulf Power is engaged, within the northwestern portion 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.

Mississippi Power is engaged in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity 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 operating companies, see MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATIONS of each traditional operating company in Item 7 herein. Also, for information relating to the sources of revenues for Southern Company, each traditional 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, 2014, there were 71 electric cooperative organizations operating in the territory in which the traditional 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, 2014, PowerSouth owned generating units with approximately 2,094 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 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. In 2010, Mississippi Power and SMEPA entered into an asset purchase agreement whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. In 2012, the Mississippi PSC approved the sale and transfer of the 17.5% undivided interest in the Kemper IGCC to SMEPA. Later in 2012, Mississippi Power and SMEPA signed an amendment to the asset purchase agreement whereby SMEPA reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC. In March 2013, Mississippi Power and SMEPA signed an amendment to the asset purchase agreement whereby Mississippi Power and SMEPA agreed to amend the power supply agreement entered into by the parties in 2011 to reduce the capacity amounts to be received by SMEPA by half (approximately 75 MWs) at the sale and transfer of the undivided interest in the Kemper IGCC to SMEPA. In December 2013, Mississippi Power and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2014.

By letter agreement dated October 6, 2014, Mississippi Power and SMEPA reached an agreement in principle on certain issues related to SMEPA's proposed purchase of a 15% undivided interest in the Kemper IGCC. The letter agreement contemplated certain amendments to the asset purchase agreement, which the parties anticipated to be incorporated into the asset purchase agreement on or before December 31, 2014. The parties agreed to further amend the asset purchase agreement as follows: (1) Mississippi Power agreed to cap at $2.88 billion the portion of the purchase price payable for development and construction costs, net of exceptions to the $2.88 billion cost cap, including the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, allowance for funds used during construction (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); title insurance reimbursement; and AFUDC and/or carrying costs through the Closing Commitment Date (defined below); (2) SMEPA agreed to close the purchase within 180 days after the date of the execution of the amended asset purchase agreement or before the Kemper IGCC's in-service date, whichever occurs first (Closing Commitment Date), subject only to satisfaction of certain conditions; and (3) AFUDC and/or carrying costs will continue to be accrued on the capped development and construction costs, the Cost Cap Exceptions, and any operating costs, net of revenues until the amended asset purchase agreement is executed by both parties, and thereafter AFUDC and/or carrying costs and payment of interest on SMEPA's deposited money will be suspended and waived, provided closing occurs by the Closing Commitment Date. The letter agreement also provided for certain post-closing adjustments to address any differences between the actual and the estimated amounts of post-in-service date costs (both expenses and capital) and revenue credits for those portions of the Kemper IGCC previously placed in service.

By letter dated December 18, 2014, SMEPA notified Mississippi Power that SMEPA decided not to extend the estimated closing date in the asset purchase agreement or revise the asset purchase agreement to include the contemplated amendments; however, both parties agree that the asset purchase agreement will remain in effect until closing or until either party gives notice of termination.

The closing of this transaction is also conditioned upon execution of a joint ownership and operating agreement, the absence of material adverse effects, receipt of all construction permits, and appropriate regulatory approvals, as well as SMEPA's receipt of RUS funding. In 2012, SMEPA received a conditional loan commitment from RUS for the purchase.

As of December 31, 2014, there were 65 municipally-owned electric distribution systems operating in the territory in which the traditional operating companies provide electric service at retail or wholesale.

As of December 31, 2014, 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 has PPAs with some of the traditional operating companies and with other investor-owned utilities, IPPs, municipalities, electric cooperatives, and an energy marketing firm. 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 operating companies, also has a contract with SEPA providing for the use of the traditional 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 United States government hydroelectric projects.

Competition

The electric utility industry in the United States 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 which 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 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, 2014, Alabama Power had cogeneration contracts in effect with 10 industrial customers. Under the terms of these contracts, Alabama Power purchases excess energy generated by such companies. During 2014, Alabama Power purchased approximately 172 million KWHs from such companies at a cost of $4.6 million.

As of December 31, 2014, Georgia Power had contracts in effect with 25 small power producers whereby Georgia Power purchases their excess generation. During 2014, Georgia Power purchased 598 million KWHs from such companies at a cost of $37 million. Georgia Power also has a PPA for electricity with one cogeneration facility. Payments are subject to reductions for failure to meet minimum capacity output. During 2014, Georgia Power purchased 197 million KWHs at a cost of $23 million from this facility.

Also during 2014, Georgia Power purchased energy from four customer-owned generating facilities. These customers provide only energy to Georgia Power and make no capacity commitment and are not dispatched by Georgia Power. During 2014, Georgia Power purchased a total of 30 million KWHs from the four customers at a cost of approximately $1 million.

As of December 31, 2014, 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 2014, Gulf Power purchased 185 million KWHs from such companies for approximately $8.1 million.

As of December 31, 2014, 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 2014, Mississippi Power did not purchase any excess generation from this customer.

Seasonality

The demand for electric power generation is affected by seasonal differences in the weather. At the traditional operating companies and Southern Power, the demand for power peaks during the summer months, with market prices reflecting the demand of power and available generating resources at that time. Power demand peaks can also be recorded during the winter. As a result, the overall operating results of Southern Company, the traditional operating companies, and Southern Power in the future may fluctuate substantially on a seasonal basis. In addition, Southern Company, the traditional operating companies, and Southern Power have historically sold less power when weather conditions are milder.

Regulation

State Commissions

The traditional operating companies are subject to the jurisdiction of their respective state PSCs. The PSCs 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 Traditional Operating Companies and Southern Power" and "Rate Matters" herein for additional information.

Federal Power Act

The traditional 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, 2014, among the hydroelectric projects subject to licensing by the FERC are 14 existing Alabama Power generating stations having an aggregate installed capacity of 1,662,400 KWs and 18 existing Georgia Power generating stations having an aggregate installed capacity of 1,087,296 KWs.

In 2005, Alabama Power filed two applications with the FERC for new 50-year licenses for its seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin) and for the Lewis Smith and Bankhead developments on the Warrior River. The FERC licenses for all of these nine projects expired in 2007. Since the FERC did not act on Alabama Power's new license applications prior to the expiration of the existing licenses, the FERC is required by law to issue annual licenses to Alabama Power, under the terms and conditions of the existing licenses, until action is taken on the new license applications.

The FERC issued annual licenses for the Coosa developments and the Warrior River developments in 2007. These annual licenses are automatically renewed each year without further action by the FERC to allow Alabama Power to continue operation of the projects under the terms of the previous license while the FERC completes review of the applications for new licenses. In 2010, the FERC issued a new 30-year license to Alabama Power for the Lewis Smith and Bankhead developments. Following the FERC's denials of their requests for rehearing and an unsuccessful appeal to the U.S. Court of Appeals for the District of Columbia Circuit, on January 30, 2015, the court dismissed the Smith Lake Improvement and Stakeholders' Association en banc rehearing request.

In June 2013, the FERC entered an order granting Alabama Power's application for relicensing of Alabama Power's seven hydroelectric developments on the Coosa River for 30 years. In July 2013, Alabama Power filed a petition requesting rehearing

of the FERC order granting the relicense seeking revisions to several conditions of the license. The Alabama Rivers Alliance, American Rivers, the Georgia Environmental Protection Division, and the Atlanta Regional Commission have also filed petitions for rehearing of the FERC order.

In 2011, Alabama Power filed an application with the FERC to relicense the Martin Dam project located on the Tallapoosa River. The Martin license expired in June 2013. Since the FERC did not act on Alabama Power's license application prior to the expiration of the existing license, the FERC issued an annual license to Alabama Power for the Martin Dam project in June 2013.

In August 2013, Alabama Power filed an application with the FERC to relicense the Holt hydroelectric project located on the Warrior River. The current Holt license will expire on August 31, 2015.

In 2012, Georgia Power filed an application with the FERC to relicense the Bartlett's Ferry project located on the Chattahoochee River near Columbus, Georgia. The FERC issued a new license on December 22, 2014.

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 period 2023-2034 in the case of Alabama Power's projects and in the period 2020-2044 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; 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 "Retail 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 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. 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.

Compliance with the federal Clean Air Act and resulting regulations has been, and will continue to be, a significant focus for Southern Company, each traditional operating company, Southern Power, and SEGCO. 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 quality, water, CCRs, global climate change,

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 operating companies in Item 7 herein for additional information about the Clean Air Act and other environmental issues, including, but not limited to, the litigation brought by the EPA under the New Source Review provisions of the Clean Air Act and proposed and final regulations related to air quality, water, greenhouse gases, and CCRs. Also 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 climate change regulation.

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 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 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 or long-term wholesale agreements for the traditional operating companies or market-based rates for Southern Power. 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. Also see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company, each of the traditional operating companies, and Southern Power 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 quality, water, CCRs, global climate change, 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' operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the electric utilities' 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. See "Construction Program" herein for additional information.

Rate Matters

Rate Structure and Cost Recovery Plans

The rates and service regulations of the traditional 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 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 – "Retail Regulatory Matters" of Southern Company and each of the traditional operating companies in Item 7 herein and Note 3 to the financial statements of Southern Company and each of the traditional 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 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 "Retail 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 and a settlement agreement between Mississippi Power and the Mississippi PSC with respect to the Kemper IGCC.

The traditional 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.

Gulf Power serves long-term contracts associated with Gulf Power's co-ownership of a unit with Georgia Power at Plant Scherer, covering 100% of Gulf Power's ownership of that unit in 2015, and 41% for the next five years. These capacity revenues represented 82% of Gulf Power's total wholesale capacity revenues for 2014. Gulf Power is actively pursuing replacement wholesale contracts but the expiration of current contracts could have a material negative impact on Gulf Power's earnings.

Mississippi Power serves 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 21.9% of Mississippi Power's operating revenues in 2014 and are largely subject to rolling 10-year cancellation notices.

Integrated Resource Planning

Each of the traditional 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 operating companies.

Certain of the traditional operating companies periodically 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 "Retail Regulatory Matters - Georgia Power - Rate Plans" and "– Nuclear Construction" and Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Integrated Resource Plans," "– Renewables Development," 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 2014. 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 Matters – Environmental Statutes and Regulations – Coal Combustion Residuals," and "Environmental Matters – 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.

Subsequent to December 31, 2014, Gulf Power announced plans to retire its coal-fired generation at Plant Smith Units 1 and 2 (357 MWs) by March 31, 2016. The plant will continue to operate and produce electricity with its other generating units on site. The retirement of these units is not expected to have a material impact on the Gulf Power's financial statements. Gulf Power expects to recover through its rates the remaining book value of the retired units and certain costs associated with the retirements; however, recovery will be considered by the Florida PSC in future rate proceedings. The net book value of these units at December 31, 2014 was approximately $80 million.

Gulf Power also has determined it is not economical to add the environmental controls at Plant Scholz necessary to comply with the MATS rule and that coal-fired generation at Plant Scholz will cease by April 2015. The plant is scheduled to be fully depreciated by April 2015.

The ultimate outcome of these matters 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 "Environmental Matters – Global Climate Issues" of Mississippi Power in Item 7 herein. On August 1, 2014, Mississippi Power entered into a settlement agreement with the Sierra Club (Sierra Club Settlement Agreement) 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. Under the Sierra Club Settlement Agreement, 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. 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, and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) and begin operating those units solely on natural gas no later than April 2016.

Mississippi 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. In February 2015, the Mississippi Supreme Court declined to rule on the constitutionality of the Baseload Act.

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.

For information regarding the February 2015 decision of the Mississippi Supreme Court related to the Baseload Act and the rates implemented in March 2013, see Note 3 to the financial statements of Southern Company under "Integrated Coal Gasification Combined Cycle – 2015 Mississippi Supreme Court Decision" and Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle - 2015 Mississippi Supreme Court Decision" 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 26,369 employees on its payroll at December 31, 2014.

	Employees at December 31, 2014
Alabama Power	6,935
Georgia Power	7,909
Gulf Power	1,384
Mississippi Power	1,478
SCS	4,395
Southern Nuclear	4,036
Southern Power*	0
Other	232
Total	26,369

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

The traditional operating companies have separate agreements with local unions of the IBEW 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, 2016.

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, which is in effect through March 15, 2016.

Southern Nuclear has an agreement with the IBEW covering certain employees at Plants Hatch and Vogtle which is in effect through June 30, 2016. 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.

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 operating companies and Southern Power, 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, asset acquisitions and sales, accounting policies and practices, physical security and cyber-security policies and practices, and the construction and operation of fossil-fuel, nuclear, hydroelectric, solar, wind, and biomass generating facilities, as well as transmission and distribution facilities. For example, the respective state PSCs must approve the traditional operating companies' requested rates for retail customers. The traditional operating companies seek to recover their costs (including a reasonable return on invested capital) through their retail rates, and there can be no assurance that a state PSC, in a future rate proceeding, will not alter the timing or amount of certain costs for which recovery is allowed or modify the current authorized rate of return. Additionally, the rates charged to wholesale customers by the traditional operating companies and by Southern Power must be approved by the FERC. These wholesale rates could be affected by changes to Southern Power's 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 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 cannot now be predicted. 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.

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, water, CCR, global climate change, renewable energy standards, 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 operating companies, and/or Southern Power.

The Southern Company system is subject to extensive federal, state, and local environmental requirements which, among other things, regulate air emissions, water usage and discharges, and the management and disposal of waste in order to adequately protect the environment. Compliance with these environmental requirements requires the traditional operating companies and Southern Power to commit significant expenditures for installation of pollution control equipment, environmental monitoring, emissions fees, and permits at substantially all of their respective facilities. Southern Company, the traditional operating companies, and Southern Power expect that these expenditures will continue to be significant in the future. Through December 31, 2014, the traditional operating companies had invested approximately $10.6 billion in environmental capital retrofit projects to comply with these requirements. The EPA has adopted and is in the process of implementing regulations governing the emission of nitrogen oxide, sulfur dioxide, fine particulate matter, mercury, and other air pollutants under the Clean Air Act through the national ambient air quality standards, CSAPR, the MATS rule, and other air quality regulations and is in the process of considering additional revisions. In addition, the EPA has recently finalized regulations governing cooling water intake structures and has proposed revisions to the effluent guidelines for steam electric generating plants and the definition of waters of the United States under the Clean Water Act. The EPA has also recently finalized regulations governing the disposal of CCR, including coal ash and gypsum, in landfills and surface impoundments at active generating power plants.

Existing environmental laws and regulations may be revised or new laws and regulations related to air quality, water, CCR, global climate change, endangered species, or other environmental and health concerns may be adopted or become applicable to the traditional operating companies and/or Southern Power.

In addition, the EPA has published three sets of proposed standards that would limit CO_2 emissions from new, existing, and

modified or reconstructed fossil-fuel-fired electric generating units. On January 8, 2014, the EPA published proposed standards for new units, and, on June 18, 2014, the EPA published proposed standards governing existing units, known as the Clean Power Plan, and separate standards governing CO_2 emissions from modified and reconstructed units. The EPA's proposed Clean Power Plan establishes guidelines for states to develop plans to address CO_2 emissions from existing fossil fuel-fired electric generating units. The EPA's proposed guidelines establish state-specific interim and final CO_2 emission rate goals to be achieved between 2020 and 2029 and 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.

The Southern Company system filed comments on the EPA's proposed Clean Power Plan on December 1, 2014. These comments addressed legal and technical issues in addition to providing a preliminary estimated cost of complying with the proposed guidelines utilizing one of the EPA's compliance scenarios. Costs associated with this proposal could be significant to the utility industry and the Southern Company system. However, the ultimate financial and operational impact of the proposed Clean Power Plan on the Southern Company system cannot be determined at this time and will depend upon numerous known and unknown factors.

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 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 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 or long-term wholesale agreements for the traditional operating companies or market-based rates for Southern Power. 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. Additionally, if Southern Company, any traditional operating company, or Southern Power 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 EPA has filed civil actions against Alabama Power and Georgia Power and issued notices of violation to Gulf Power and Mississippi Power alleging violations of the new source review provisions of the Clean Air Act. An adverse outcome in any of these matters could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties.

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 United States. 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 cost impact of proposed and final legislation and regulations and litigation are likely to result in significant and additional costs and could result in additional operating restrictions.

The net income of Southern Company, the traditional 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 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 of 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. Southern Company, the traditional operating companies, and Southern Power cannot predict the impact of these and other such developments, nor can they predict the effect of changes in levels of wholesale supply and demand, which are typically driven by factors beyond their control. The financial condition, net income, and cash flows of Southern Company, the traditional operating companies, and Southern Power could be adversely affected by these and other changes.

The traditional 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 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 operating companies, Southern Power, and Southern Company to higher operating costs and/or increased capital expenditures. If any traditional operating company or Southern Power is found to be in noncompliance with the mandatory reliability standards, such traditional operating company or Southern Power could be subject to sanctions, including substantial monetary penalties.

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 its subsidiaries' electric generating, transmission, and distribution 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, particularly with older generating facilities;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- terrorist attacks;
- fuel or material supply interruptions;
- transmission disruption or capacity constraints, including with respect to the Southern Company system's transmission facilities and third party transmission facilities;
- compliance with mandatory reliability standards, including mandatory cyber security standards;
- implementation of technologies with which the Southern Company system is developing experience;
- information technology system failure;
- cyber intrusion;
- an environmental event, such as a spill or release; and
- catastrophic events such as fires, earthquakes, explosions, floods, droughts, hurricanes, 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 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 operating company or Southern Power and of Southern Company. In addition, an investment in a subsidiary with such generation, transmission, or distribution facilities could be adversely impacted.

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 7.9%, of the Southern Company system's generation capacity as of December 31, 2014. In addition, these units generated approximately 23% and 22% of the total KWHs generated by Alabama Power and Georgia Power, respectively, in the year ended December 31, 2014. 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 United States;
- 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 limit, prohibit, or require significant changes to the operation or licensing of any domestic nuclear unit that could result in substantial costs. Moreover, a major incident at any nuclear facility in the United States, 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.

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

The traditional operating companies and Southern Power face the risk of physical and cyber attacks, both threatened and actual, against their respective generation facilities, the transmission and distribution infrastructure used to transport power, and their information technology systems and network infrastructure, which could negatively impact the ability of the traditional operating companies or Southern Power to generate, transport, and deliver power, or otherwise operate their respective 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 operating companies and Southern Power operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure, which are part of an interconnected regional grid. In addition, in the ordinary course of business, the traditional operating companies and Southern Power collect and retain sensitive information including personal identification information about customers and employees and other confidential information. The traditional operating companies and Southern Power 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 operating companies' or Southern Power's assets were to fail, be physically damaged, or be breached and were not recovered in a timely way, the traditional operating companies or Southern Power 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 operating company or Southern Power 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 operating companies, or Southern Power through lost revenues, costs to recover and repair damage, and costs associated with governmental actions in response to such attacks.

The traditional operating companies and Southern Power may not be able to obtain adequate fuel supplies, which could limit their ability to operate their facilities.

The traditional operating companies and Southern Power purchase fuel, including coal, natural gas, uranium, fuel oil, and biomass, 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 operating companies and Southern Power to operate their respective facilities, and thus reduce the net income of the affected traditional operating company or Southern Power and Southern Company.

The traditional operating companies are dependent on coal for a portion of their electric generating capacity. The traditional operating companies depend on coal supply contracts, and there can be no assurance that the counterparties to these agreements will fulfill their obligations to supply coal to the traditional operating companies. The suppliers under these agreements may experience financial or technical problems which inhibit their ability to fulfill their obligations to the traditional operating companies. In addition, the suppliers under these agreements may not be required to supply coal to the traditional operating companies under certain circumstances, such as in the event of a natural disaster. If the traditional operating companies are unable to obtain their coal requirements under these contracts, the traditional operating companies may be required to purchase their coal requirements at higher prices, which may not be recoverable through rates.

In addition, the traditional operating companies and Southern Power to a greater extent 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 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 operating companies' reliance on natural gas-fired generating units.

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. The availability of shale gas and potential regulations affecting its accessibility may have a material impact on the supply and cost of natural gas.

In addition, world market conditions for fuels can impact the cost and availability of natural gas, coal, and uranium.

The revenues of Southern Company, the traditional 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, 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 operating company or Southern Power and of Southern Company.

Most of Southern Power's generating capacity has been sold to purchasers under PPAs. In addition, the traditional 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 operating company or Southern Power and of Southern Company. Although the credit evaluations undertaken and contractual protections implemented by Southern Power and the traditional 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 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.

Changes in technology may make Southern Company's electric generating facilities owned by the traditional operating companies and Southern Power less competitive.

A key element of the business models of Southern Company, the traditional 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 technologies that produce power, including fuel cells, microturbines, wind turbines, and solar cells. 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. Broader use of distributed generation by retail electric customers may also result from customers' changing perceptions of the merits of utilizing existing generation technology or tax or other economic incentives. Additionally, there can be no assurance that a state PSC or legislature will not attempt to modify certain aspects of the traditional operating companies' business as a result of these advances in technology. If these technologies became cost competitive and achieved sufficient scale, the market share of the traditional operating companies and Southern Power could be eroded, and the value of their respective electric generating facilities could be reduced. 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 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 operating companies, or Southern Power. If state PSCs 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 traditional operating companies 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, especially with the workforce needs associated with the Kemper IGCC and Plant Vogtle Units 3 and 4 construction. 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, including the traditional operating companies, are unable to successfully attract and retain an appropriately qualified workforce, results of operations could be negatively impacted.

CONSTRUCTION RISKS

Southern Company, the traditional operating companies, and/or Southern Power 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 operating companies and Southern Power 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 capital improvements to transmission, distribution, and generation facilities, including those to meet environmental standards. Certain of the traditional operating companies and Southern Power are in the process of constructing new generating facilities and adding environmental controls equipment at existing generating facilities. The Southern Company system intends to continue its strategy of developing and constructing other new facilities, expanding 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;
- labor costs and productivity;
- work stoppages;
- contractor or supplier delay or non-performance under construction 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, system integration, and operations, and/or unforeseen engineering problems;
- 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 licensing requirements;
- continued public and policymaker support for such projects;
- adverse weather conditions or natural disasters;
- other unforeseen engineering 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.

In addition, with respect to the construction of Plant Vogtle Units 3 and 4 and the operation of existing nuclear units, 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.

If a traditional operating company or Southern Power is unable to complete the development or construction of a facility or decides to delay or cancel construction of a facility, it may not be able to recover its investment in that facility and may incur substantial cancellation payments under equipment purchase orders or construction contracts. Even if a construction project is completed, the total costs may be higher than estimated and there is no assurance that the traditional operating company will 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 operating company or Southern Power and of Southern Company.

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

Once facilities come into commercial operation, ongoing capital expenditures are required to maintain reliable levels of operation. Significant portions of the traditional operating companies' existing facilities were constructed many years ago. Older generation 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 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.

Plant Vogtle Units 3 and 4 construction

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. The NRC certified the Westinghouse Electric Company LLC's Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, in late 2011, and issued combined COLs in early 2012. Receipt of the COLs allowed full construction to begin. 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 are expected as construction proceeds.

Georgia Power, OPC, MEAG Power, and Dalton (collectively, Vogtle Owners) and Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc., a subsidiary of the Shaw Group Inc., which was acquired by Chicago Bridge & Iron Company N.V. (collectively, Contractor) are involved in litigation regarding the costs associated with design changes to the DCD and the delays in the timing of approval of the DCD and issuance of the COLs, including the assertion by the Contractor

that the Vogtle Owners are responsible for these costs under the terms of the agreement with the Contractor (Vogtle 3 and 4 Agreement). Also in 2012, Georgia Power and the other Vogtle Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Vogtle Owners are not responsible for these costs. In 2012, the Contractor also filed suit against Georgia Power and the other Vogtle Owners in the U.S. District Court for the District of Columbia alleging the Vogtle Owners are responsible for these costs. In August 2013, the U.S. District Court for the District of Columbia dismissed the Contractor's suit, ruling that the proper venue is the U.S. District Court for the Southern District of Georgia. The Contractor appealed the decision to the U.S. Court of Appeals for the District of Columbia Circuit in September 2013. The portion of additional costs claimed by the Contractor in its initial complaint that would be attributable to Georgia Power (based on Georgia Power's ownership interest) is approximately $425 million (in 2008 dollars). The Contractor also asserted it is entitled to extensions of the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. On May 22, 2014, the Contractor filed an amended counterclaim to the suit pending in the U.S. District Court for the Southern District of Georgia alleging that (i) the design changes to the DCD imposed by the NRC delayed module production and the impacts to the Contractor are recoverable by the Contractor under the Vogtle 3 and 4 Agreement and (ii) the changes to the basemat rebar design required by the NRC caused additional costs and delays recoverable by the Contractor under the Vogtle 3 and 4 Agreement. The Contractor did not specify in its amended counterclaim the amounts relating to these new allegations; however, the Contractor has subsequently asserted related minimum damages (based on Georgia Power's ownership interest) of $113 million. The Contractor may from time to time continue to assert that it is entitled to additional payments with respect to these allegations, any of which could be substantial. Georgia Power has not agreed to the proposed cost or to any changes to the guaranteed substantial completion dates or that the Vogtle Owners have any responsibility for costs related to these issues. Litigation is ongoing and Georgia Power intends to vigorously defend the positions of the Vogtle Owners. Georgia Power also expects negotiations with the Contractor to continue with respect to cost and schedule during which negotiations the parties may reach a mutually acceptable compromise of their positions.

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. If the projected certified construction capital costs to be borne by Georgia Power increase by 5% or the projected in-service dates are significantly extended, Georgia Power is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. Georgia Power's eighth VCM report filed in February 2013 requested an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 from $4.4 billion to $4.8 billion and to extend the estimated in-service dates to the fourth quarter 2017 and the fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively.

In September 2013, the Georgia PSC approved a stipulation (2013 Stipulation) entered into by 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 accordance with the Georgia Integrated Resource Planning Act, any costs incurred by Georgia Power in excess of the certified amount will be included in rate base, provided Georgia Power shows the costs to be reasonable and prudent. In addition, financing costs on any construction-related costs in excess of the certified amount likely would be subject to recovery through AFUDC instead of the Nuclear Construction Cost Recovery tariff.

The Georgia PSC has approved eleven VCM reports covering the periods through June 30, 2014, including construction capital costs incurred, which through that date totaled $2.8 billion.

On January 29, 2015, Georgia Power announced that it was notified by the Contractor of the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4, which would incrementally delay the previously disclosed estimated in-service dates by 18 months (from the fourth quarter of 2017 to the second quarter of 2019 for Unit 3 and from the fourth quarter of 2018 to the second quarter of 2020 for Unit 4). Georgia Power has not agreed to any changes to the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. Georgia Power does not believe that the Contractor's revised forecast reflects all efforts that may be possible to mitigate the Contractor's delay.

In addition, Georgia Power believes that, pursuant to the Vogtle 3 and 4 Agreement, the Contractor is responsible for the Contractor's costs related to the Contractor's delay (including any related construction and mitigation costs, which could be material) and that the Vogtle Owners are entitled to recover liquidated damages for the Contractor's delay beyond the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. Consistent with the Contractor's position in the pending litigation described above, Georgia Power expects the Contractor to contest any claims for liquidated damages and to assert that the Vogtle Owners are responsible for additional costs related to the Contractor's delay. The Contractor's liability to the Vogtle Owners for schedule and performance liquidated damages and warranty claims is subject to a cap. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which have not occurred), with maximum additional capital costs under this provision attributable to Georgia Power (based on Georgia Power's ownership interest) of approximately $114 million.

On February 27, 2015, Georgia Power filed its twelfth VCM report with the Georgia PSC covering the period from July 1 through December 31, 2014, which requests approval for an additional $0.2 billion of construction capital costs incurred during that period and reflects the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4 as well as additional estimated owner-related costs of approximately $10 million per month expected to result from the Contractor's proposed 18-month delay, including property taxes, oversight costs, compliance costs, and other operational readiness costs. No Contractor costs related to the Contractor's proposed 18-month delay are included in the twelfth VCM report. Additionally, while Georgia Power has not agreed to any change to the guaranteed substantial completion dates, the twelfth VCM report includes a requested amendment to the Plant Vogtle Units 3 and 4 certificate to reflect the Contractor's revised forecast, to include the estimated owner's costs associated with the proposed 18-month Contractor delay, and to increase the estimated total in-service capital cost of Plant Vogtle Units 3 and 4 to $5.0 billion.

Georgia Power will continue to incur financing costs of approximately $30 million per month until Plant Vogtle Units 3 and 4 are placed in service. The twelfth VCM report estimates total associated financing costs during the construction period to be approximately $2.5 billion.

Processes are in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, 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 issues are expected to 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.

As construction continues, the risk remains that ongoing challenges with Contractor performance including additional challenges in its fabrication, assembly, delivery, and installation of the shield building and structural modules, delays in the receipt of the remaining permits necessary for the operation of Plant Vogtle Units 3 and 4, or other issues could arise and may further impact project schedule and cost. In addition, the IRS allocated production tax credits to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021. Additional claims by the Contractor or Georgia Power (on behalf of the Vogtle Owners) are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the engineering, procurement, and construction agreement for Plant Vogtle Units 3 and 4, but also may be resolved through litigation.

Kemper IGCC construction

In 2012, the Mississippi PSC issued a detailed order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC (2012 MPSC CPCN Order). The 2012 MPSC CPCN Order included a certificated cost estimate of $2.4 billion, net of the DOE Grants and excluding the Cost Cap Exceptions described below, and approved a construction cost cap of up to $2.88 billion, with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. As discussed below, the 2013 Settlement Agreement, among other things, established processes for resolving matters regarding cost recovery (both during construction and startup and following commercial operation of the Kemper IGCC), including the treatment of costs in excess of the $2.88 billion cost cap.

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 on natural gas on August 9, 2014 and continues to focus on completing the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, for which the in-service date is currently expected to occur in the first half of 2016.

Mississippi Power does not intend to seek any rate recovery or joint owner contributions for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the 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). Through December 31, 2014, Southern Company and Mississippi Power recorded pre-tax charges to income as a result of increases to the cost estimate of $2.05 billion ($1.26 billion after tax). Primarily as a result of these charges, Mississippi Power incurred net losses after dividends on preferred stock of $328.7 million and $476.6 million in the years ended December 31, 2014 and 2013, respectively. The current estimate includes costs through March 31, 2016. Any further extension of the in-service date is currently estimated to result in additional base costs of approximately $25 million to $30 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. Any further extension of the in-service date with respect to the Kemper IGCC 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 $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees, which are being deferred as regulatory assets and are estimated to total approximately $7 million per month.

Any further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (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). In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the 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.

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. The 2013 Settlement Agreement also allowed Mississippi Power to secure alternate financing for costs not otherwise recovered in any Mississippi PSC rate proceedings contemplated by the 2013 Settlement Agreement.

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 February 2013. Mississippi Power's intent under the 2013 Settlement Agreement was to securitize (1) prudently-incurred costs in excess of the certificated cost estimate and up to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, (2) accrued AFUDC, and (3) other prudently-incurred costs, which include carrying costs from the estimated in-service date until securitization is finalized and other costs not included in the Rate Mitigation Plan (described below) as approved by the Mississippi PSC.

Consistent with the terms of the 2013 Settlement Agreement, in March 2013, the Mississippi PSC issued a rate order (2013 MPSC 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. For the period from March 2013 through December 31, 2014, $257.2 million had been collected primarily to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service.

On August 18, 2014, Mississippi Power provided the Mississippi PSC with an analysis of the costs and benefits of placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service, including the expected accounting treatment. Mississippi Power's analysis requested, among other things, confirmation by the Mississippi PSC of the continued collection of rates as prescribed by the 2013 MPSC Rate Order, with the current recognition as revenue of the related equity return on all assets placed in service and the deferral of all remaining rate collections under the 2013 MPSC Rate Order to a regulatory liability account. As discussed further below, a February 2015 decision of the Mississippi Supreme Court would discontinue the collection of, and require the refund of, all amounts previously collected under the 2013 MPSC Rate Order.

In addition, Mississippi Power's August 18, 2014 filing with the Mississippi PSC requested confirmation of Mississippi Power's accounting treatment by the Mississippi PSC of the continued accrual of AFUDC through the in-service date of the remainder of the Kemper IGCC and the deferral of operating costs as regulatory assets. Any action by the Mississippi PSC that is inconsistent with the treatment requested by Mississippi Power could have a material impact on the results of operations, financial condition, and liquidity of Mississippi Power and Southern Company.

Also consistent with the 2013 Settlement Agreement, Mississippi Power has filed with the Mississippi PSC a rate recovery plan for the Kemper IGCC for cost recovery through 2020 (Rate Mitigation Plan), which is still under review by the Mississippi PSC. The revenue requirements set forth in the Rate Mitigation Plan assume the sale of a 15% undivided interest in the Kemper IGCC to SMEPA and utilization of bonus depreciation, which currently requires that the related long-term asset be placed in service in 2015.

On February 12, 2015, the Mississippi Supreme Court (Court) issued its decision in the legal challenge to the 2013 MPSC Rate Order filed by Thomas A. Blanton. The Court reversed the 2013 MPSC Rate Order based on, among other things, its findings that (1) the collection of $156 million annually to be set aside in a regulatory liability account for use in mitigating future rate impacts for customers (Mirror CWIP) 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. The Court's ruling remands the matter to the Mississippi PSC to (1) fix by order the rates that were in existence prior to the 2013 MPSC

Rate Order, (2) fix no rate increases until the Mississippi PSC is in compliance with the Court's ruling, and (3) enter an order refunding amounts collected under the 2013 MPSC Rate Order. Through December 31, 2014, Mississippi Power had collected $257.2 million through rates under the 2013 MPSC Rate Order. Any required refunds would also include carrying costs. The Court's decision will become legally effective upon the issuance of a mandate to the Mississippi PSC. Absent specific instruction from the Court, the Mississippi PSC will determine the method and timing of the refund. Mississippi Power is reviewing the Court's decision and expects to file a motion for rehearing which would stay the Court's mandate until either the case is reheard and decided or seven days after the Court issues its order denying Mississippi Power's request for rehearing. Mississippi Power is also evaluating its regulatory options.

To the extent that refunds of amounts collected under the 2013 MPSC Rate Order are required on a schedule different from the amortization schedule proposed in the Rate Mitigation Plan, the customer billing impacts proposed under the Rate Mitigation Plan would no longer be viable.

In the event that the Mirror CWIP regulatory liability is refunded to customers prior to the in-service date of the Kemper IGCC and is, therefore, not available to mitigate rate impacts under the Rate Mitigation Plan, the Mississippi PSC does not approve a refund schedule that facilitates rate mitigation, or Mississippi Power withdraws the Rate Mitigation Plan, Mississippi Power would seek rate recovery through alternate means, which could include a traditional rate case.

In addition to current estimated costs at December 31, 2014 of $6.20 billion, Mississippi Power anticipates that it will incur additional costs after the Kemper IGCC in-service date until the Kemper IGCC cost recovery approach is finalized. These costs include, but are not limited to, regulatory costs and additional carrying costs which could be material. Recovery of these costs would be subject to approval by the Mississippi PSC.

The Mississippi PSC's review of Kemper IGCC costs is ongoing. On August 5, 2014, the Mississippi PSC ordered that a consolidated prudence determination of all Kemper IGCC costs be completed after the entire project has been placed in service and has demonstrated availability for a reasonable period of time as determined by the Mississippi PSC and the Mississippi Public Utilities Staff. The Mississippi PSC has encouraged the parties to work in good faith to settle contested issues and Mississippi Power is working to reach a mutually acceptable resolution. As a result of the Court's decision, Mississippi Power intends to request that the Mississippi PSC reconsider its prudence review schedule.

Mississippi Power expects the Mississippi PSC to include operational parameters in its evaluation of the Rate Mitigation Plan and other related proceedings during the operation of the Kemper IGCC. To the extent the Kemper IGCC does not satisfy the operational parameters ultimately adopted by the Mississippi PSC or Mississippi Power incurs additional costs in order to satisfy such parameters, there could be a material adverse effect on Southern Company's and Mississippi Power's results of operations, financial condition, and liquidity.

In addition, any failure to place the Kemper IGCC in-service by April 15, 2016 or to capture and sequester (via enhanced oil recovery) at least 65% of the carbon dioxide produced by the Kemper IGCC during operations in accordance with IRS requirements would result in the loss of Phase II tax credits that have been allocated to the Kemper IGCC. Through December 31, 2014, Southern Company and Mississippi Power have recorded tax benefits totaling $276 million, of which approximately $210 million have been utilized through that date.

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.

FINANCIAL, ECONOMIC, AND MARKET RISKS

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

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

- prevailing market prices for coal, natural gas, uranium, fuel oil, biomass, and other fuels used in the generation facilities of the traditional operating companies and Southern Power, 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 market;
- weather conditions impacting demand for electricity;
- 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 service territory, the nation, and worldwide, including the impact of economic conditions on demand for electricity and the demand for fuels;
- 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 operating companies or Southern Power and Southern Company. For the traditional operating companies, such increases may not be fully recoverable through rates. Other of these factors could reduce the revenues of the traditional operating companies or Southern Power and Southern Company.

Historically, the traditional operating companies from time to time have experienced underrecovered fuel cost balances and may experience such balances in the future. While the traditional operating companies are generally authorized to recover underrecovered fuel costs through fuel 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 operating company and Southern Company.

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

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 electricity 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 operating companies and Southern Power.

Outside of economic disruptions, changes in customer behaviors in response to changing conditions and preferences or changes in the adoption of technologies could affect the relationship of economic activity to the consumption of electricity. On the customer behavior side, federal and state programs exist to influence how customers use energy, and several of the traditional operating companies have PSC mandates to promote energy efficiency. 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 technologies such as electric vehicles can create additional demand. There can be no assurance that the Southern Company system's planning processes will appropriately estimate and incorporate the impacts of changes in customer behavior, state and federal programs, PSC mandates, and technology.

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

The operating results of Southern Company, the traditional operating companies, and Southern Power 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 operating companies and/or Southern Power and could negatively impact results of operation, financial condition, and liquidity.

Electric power supply is generally a seasonal business. 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. As a result, the overall operating results of Southern Company, the traditional operating companies, and Southern Power may fluctuate substantially on a seasonal basis. In addition, the traditional operating companies and Southern Power have historically sold less power 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 operating companies, and/or Southern Power.

In addition, volatile or significant weather events could result in substantial damage to the transmission and distribution lines of the traditional operating companies and the generating facilities of the traditional operating companies and Southern Power. The traditional operating companies and Southern Power have significant investments in the Atlantic and Gulf Coast regions which could be subject to major storm activity. 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 operating company 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. Historically, the traditional 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 delay in recovery of any portion of such costs could have a material negative impact on a traditional operating company's 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 operating company or affecting Southern Power's customers may result in the loss of customers and reduced demand for electricity for extended periods. Any significant loss of customers or reduction in demand for electricity could have a material negative impact on a traditional operating company's or Southern Power's and Southern Company's results of operations, financial condition, and liquidity.

Acquisitions and dispositions 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 dispositions in the past and may in the future make additional acquisitions and dispositions. Southern Power, in particular, continually seeks opportunities to create value through various transactions, including acquisitions or sales of assets.

Southern Company and its subsidiaries may face significant competition for acquisition opportunities and there can be no assurance that anticipated acquisitions will 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:

- any acquisitions may not result in an increase in income or provide an adequate return of capital or other anticipated benefits;
- any acquisitions may not be successfully integrated into the acquiring company's operations and internal controls;
- the due diligence conducted prior to an acquisition 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;
- any disposition may result in decreased earnings, revenue, or cash flow;
- use of cash for acquisitions may adversely affect cash available for capital expenditures and other uses; or
- any dispositions, investments, or acquisitions could have a material adverse effect on the liquidity, results of operations, or financial condition of Southern Company or its subsidiaries.

Southern Company may be unable to meet its ongoing and future financial obligations and to pay dividends on its common stock if its subsidiaries are unable to pay upstream dividends or repay funds to Southern Company.

Southern Company is a holding company and, as such, Southern Company has no operations of its own. Substantially all of Southern Company's consolidated assets are held by subsidiaries. Southern Company's ability to meet its financial obligations and to pay dividends on its common stock is primarily dependent on the net income and cash flows of its subsidiaries and their ability to pay upstream dividends or to repay funds to Southern Company. Prior to funding Southern Company, Southern Company's subsidiaries have regulatory restrictions and financial obligations that must be satisfied, including among others, debt service and preferred and preference stock dividends. Southern Company's subsidiaries are separate legal entities and have no obligation to provide Southern Company with funds.

A downgrade in the credit ratings of Southern Company, any of the traditional operating companies, or Southern Power Company could negatively affect their ability to access capital at reasonable costs and/or could require Southern Company, the traditional operating companies, or Southern Power Company 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 operating companies, and Southern Power Company, including capital structure, regulatory environment, the ability to cover liquidity requirements, and other commitments for capital. Southern Company, the traditional operating companies, and Southern Power Company 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 operating companies, or Southern Power Company 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 operating companies, or Southern Power Company, borrowing costs would increase, 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 operating company or Southern Power Company to alter the mix of debt financing currently used, and could require the issuance of secured indebtedness and/or indebtedness with additional restrictive covenants.

Demand for power could decrease or fail to grow at expected rates, resulting in stagnant or reduced revenues, limited growth opportunities, and potentially stranded generation assets.

Southern Company, the traditional 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. This planning process must look many years into the future in order to accommodate the long lead times associated with the permitting and construction of new generation facilities. Inherent risk exists in predicting demand this far into the future as these future loads are dependent on many uncertain factors, including regional economic conditions, customer usage patterns, efficiency programs, and customer technology adoption. Because regulators may not permit the traditional operating companies to adjust rates to recover the costs of new generation assets while such assets are being constructed, the traditional operating companies 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 of additional capacity and the traditional operating companies' 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 operating companies may not be able to extend existing PPAs or to 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 operating company or Southern Power and for Southern Company.

Demand for power could exceed supply capacity, resulting in increased costs for purchasing capacity in the open market or building additional generation and transmission facilities.

The traditional operating companies and Southern Power are currently obligated to supply power to retail customers and 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 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 operating companies to pass all of these purchase or construction costs on to their customers, the traditional 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 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 operating company or Southern Power and for Southern Company.

Energy conservation and energy price increases could negatively impact financial results.

Customers could voluntarily reduce their consumption of electricity in response to decreases in their disposable income, increases in energy prices, or individual conservation efforts, which could negatively impact the results of operations of Southern Company, the traditional operating companies, and Southern Power. In addition, a number of regulatory and legislative bodies have proposed or introduced requirements and/or incentives to reduce energy consumption by certain dates. Conservation programs could impact the financial results of Southern Company, the traditional operating companies, and Southern Power in different ways. For example, if any traditional operating company 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 operating company and Southern Company.

Certain of the traditional operating companies actively promote energy conservation programs, which have been approved by their respective state PSCs. For certain of such traditional operating companies, regulatory mechanisms have been established that provide for the recovery of costs related to such programs and lost revenues as a result of such programs. However, to the extent conservation results in reduced energy demand or significantly slows the growth in demand beyond what is anticipated, the value of generation assets of the traditional operating companies and/or Southern Power and other unregulated business activities could be adversely impacted and the traditional operating companies could be negatively impacted depending on the regulatory treatment of the associated impacts. In addition, the failure of those traditional operating companies that actively promote energy conservation programs to achieve the energy conservation targets established by their respective state PSCs could negatively impact such traditional operating companies' ability to recover costs and lost revenues as a result of such progress and ability to receive certain benefits related to such programs.

Southern Company, the traditional operating companies, and Southern Power are unable to determine what impact, if any, conservation and increases in energy prices will have on their respective financial condition or results of operations.

The businesses of Southern Company, the traditional operating companies, and Southern Power are dependent on their ability to successfully access funds through capital markets and financial institutions. The inability of Southern Company, any traditional operating company, or Southern Power 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 operating companies, or Southern Power may otherwise rely on to achieve future earnings and cash flows.

Southern Company, the traditional operating companies, and Southern Power 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 operating company, or Southern Power 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 operating companies, or Southern Power may otherwise rely on to achieve future earnings and cash flows. In addition, Southern Company, the traditional operating companies, and Southern Power 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 operating companies, and Southern Power 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 such as dividend tax rates;
- market prices for electricity and gas;
- terrorist attacks or threatened attacks on Southern Company's facilities or unrelated energy companies' facilities;
- war or threat of war; or
- the overall health of the utility and financial institution industries.

In addition, 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, compliance with the Cargo Preference Act of 1954, 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.

Market performance and other changes may decrease the value of benefit plans and nuclear decommissioning trust assets or may increase plan costs, which then could require significant additional funding.

The performance of the capital markets affects the values of the assets held in trust under Southern Company's pension and postretirement benefit plans and the assets held in trust to satisfy obligations to decommission Alabama Power's and Georgia Power's nuclear plants. The Southern Company system has significant obligations related to pension and postretirement benefit

plans. Alabama Power and Georgia Power each hold significant assets in the nuclear decommissioning trusts. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below projected return rates. A decline in the market value of these assets may increase the funding requirements relating to benefit plan liabilities of the Southern Company system and Alabama Power's and Georgia Power's nuclear decommissioning obligations. Additionally, changes in interest rates affect the liabilities under pension and postretirement benefit plans of the Southern Company system; as interest rates decrease, the liabilities increase, potentially requiring additional funding. Further, changes in demographics, including an increased number of retirements or changes in life expectancy assumptions, may also increase the funding requirements of the obligations related to the pension benefit plans. Southern Company and its subsidiaries are also facing rising medical benefit costs, including the current costs for active and retired employees. It is possible that these costs may increase at a rate that is significantly higher than anticipated. If the Southern Company system is unable to successfully manage benefit plan assets and medical benefit costs and Alabama Power and Georgia Power are unable to successfully manage the nuclear decommissioning trust funds, results of operations and financial position could be negatively affected.

Southern Company, the traditional operating companies, and Southern Power 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 operating companies, Southern Power, and their respective competitors typically insure against may decrease, and the insurance that Southern Company, the traditional operating companies, and Southern Power are able to obtain may have higher deductibles, higher premiums, and more restrictive policy terms. Further, there is no guarantee that the insurance policies maintained by the Southern Company, the traditional operating companies, and Southern Power will 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 operating companies, or Southern Power.

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.

Southern Company and its subsidiaries, including the traditional operating companies and Southern Power, use derivative instruments, such as swaps, options, futures, and forwards, to manage their commodity and interest rate exposures and, to a lesser extent, 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 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 value of the reported fair value of these contracts.

Item 1B. UNRESOLVED STAFF COMMENTS.

None.

Item 2. PROPERTIES

Electric Properties

The traditional operating companies, Southern Power, and SEGCO, at December 31, 2014, owned and/or operated 33 hydroelectric generating stations, 33 fossil fuel generating stations, three nuclear generating stations, and 13 combined cycle/ cogeneration stations, nine solar facilities, one biomass facility, and one landfill gas facility. The amounts of capacity for each company, as of December 31, 2014, are shown in the table below.

Generating Station	Location	Nameplate Capacity (1) (KWs)	
FOSSIL STEAM			
Gadsden	Gadsden, AL	120,000	
Gorgas	Jasper, AL	1,221,250	(2)
Barry	Mobile, AL	1,525,000	(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		6,578,538	
Bowen	Cartersville, GA	3,160,000	
Branch	Milledgeville, GA	1,220,700	(5)
Hammond	Rome, GA	800,000	
Kraft	Port Wentworth, GA	281,136	(5)
McIntosh	Effingham County, GA	163,117	
McManus	Brunswick, GA	115,000	(5)
Mitchell	Albany, GA	125,000	(6)
Scherer	Macon, GA	750,924	(7)
Wansley	Carrollton, GA	925,550	(8)
Yates	Newnan, GA	1,250,000	(5)
Georgia Power Total		8,791,427	
Crist	Pensacola, FL	970,000	
Daniel	Pascagoula, MS	500,000	(9)
Lansing Smith	Panama City, FL	305,000	(10)
Scholz	Chattahoochee, FL	80,000	(10)
Scherer Unit 3	Macon, GA	204,500	(7)
Gulf Power Total		2,059,500	
Daniel	Pascagoula, MS	500,000	(9)
Greene County	Demopolis, AL	200,000	(3)
Sweatt	Meridian, MS	80,000	(11)
Watson	Gulfport, MS	1,012,000	(11)
Mississippi Power Total		1,792,000	
Gaston Units 1-4	Wilsonville, AL		
SEGCO Total		1,000,000	(12)
Total Fossil Steam		20,221,465	

Generating Station	Location	Nameplate Capacity (1)	
IGCC			
Kemper County/Ratcliffe	Kemper County, MS	778,772	(13)
Total IGCC		778,772	
NUCLEAR STEAM			
Farley	Dothan, AL		
Alabama Power Total		1,720,000	
Hatch	Baxley, GA	899,612	(14)
Vogtle Units 1 and 2	Augusta, GA	1,060,240	(15)
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	(5)
Intercession City	Intercession City, FL	47,667	(16)
Kraft	Port Wentworth, GA	22,000	
McDonough Unit 3	Atlanta, GA	78,800	
McIntosh Units 1 through 8	Effingham County, GA	640,000	
McManus	Brunswick, GA	481,700	
Mitchell	Albany, GA	78,800	
Robins	Warner Robins, GA	158,400	
Wansley	Carrollton, GA	26,322	(8)
Wilson	Augusta, GA	354,100	
Georgia Power Total		1,907,489	
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	(17)
Sweatt	Meridian, MS	39,400	
Watson	Gulfport, MS	39,360	
Mississippi Power Total		226,052	
Addison (formally West Georgia)	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	(12)
Total Combustion Turbines		6,318,972	
COGENERATION			
Washington County	Washington County, AL	123,428	
GE Plastics Project	Burkeville, AL	104,800	
Theodore	Theodore, AL	236,418	
Total Cogeneration		464,646	
COMBINED CYCLE			
Barry	Mobile, AL		

Generating Station	Location	Nameplate Capacity (1)	
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	
Rowan	Salisbury, NC	530,550	
Stanton Unit A	Orlando, FL	428,649	(18)
Wansley	Carrollton, GA	1,073,000	
Southern Power Total		5,208,939	
Total Combined Cycle		11,734,207	
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	(19)
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	
6 Other Plants	Various Georgia Cities	18,080	
Georgia Power Total		1,087,536	
Total Hydroelectric Facilities		2,755,615	

Generating Station	Location	Nameplate Capacity (1)	
RENEWABLE SOURCES:			
SOLAR FACILITIES			
Dalton	Dalton, GA	7,769	
Georgia Power Total		7,769	
Adobe	Kern County, CA	20,000	
Apex	North Las Vegas, NV	20,000	
Campo Verde	Imperial County, CA	147,420	
Cimarron	Springer, NM	30,640	
Granville	Oxford, NC	2,500	
Imperial Valley	Imperial County, CA	163,200	
Macho Springs	Luna County, NM	55,000	
Spectrum	Clark County, NV	30,240	
Southern Power Total		469,000	(20)
Total Solar		476,769	
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		46,548,998	

Notes:

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

(2) As part of its environmental compliance strategy, Alabama Power plans to retire Plant Gorgas Units 6 and 7 (200MWs). Alabama Power also plans to cease 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. Additionally, Alabama Power expects to cease using coal at Plant Barry Unit 3 (225 MWs) and begin operating that unit solely on natural gas. These plans are expected to be effective no later than April 2016. See MANAGEMENT'S DISCUSSION AND ANALYSIS - FUTURE EARNINGS POTENTIAL - "Retail Regulatory Matters - Alabama Power - Environmental Accounting Order" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS - FUTURE EARNINGS POTENTIAL - "Retail Regulatory Matters - Environmental Accounting Order" of Alabama Power in Item 7 herein. See also Note 3 to the financial statements of Southern Company and Alabama Power under "Retail Regulatory Matters - Alabama Power - Environmental Accounting Order" and "Retail Regulatory Matters - Environmental Accounting Order," respectively, in Item 8 herein.

(3) Owned by Alabama Power and Mississippi Power as tenants in common in the proportions of 60% and 40%, respectively. Alabama Power and Mississippi Power plan to cease using coal and to operate these units solely on natural gas no later than April 2016. See MANAGEMENT'S DISCUSSION AND ANALYSIS - FUTURE EARNINGS POTENTIAL - "Retail Regulatory Matters - Alabama Power - Environmental Accounting Order" of Southern Company, MANAGEMENT'S DISCUSSION AND ANALYSIS - FUTURE EARNINGS POTENTIAL - "Retail Regulatory Matters - Environmental Accounting Order" of Alabama Power, and MANAGEMENT'S DISCUSSION AND ANALYSIS - FUTURE EARNINGS POTENTIAL - "Retail Regulatory Matters - Environmental Compliance Overview Plan" of Mississippi Power in Item 7 herein. See also Note 3 to the financial statements of Southern Company, Alabama Power, and Mississippi Power under "Retail 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) See MANAGEMENT'S DISCUSSION AND ANALYSIS - FUTURE EARNINGS POTENTIAL - "Retail Regulatory Matters - Georgia Power - Integrated Resource Plans" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS - FUTURE EARNINGS POTENTIAL - "Retail Regulatory Matters - Integrated Resource Plans" of Georgia Power in Item 7 herein. See also Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters - Georgia Power - Integrated Resource Plans" and "Retail Regulatory Matters - Integrated Resource Plans," respectively, in Item 8 herein for information on plant retirements, fuel switching, and conversions.

(6) Georgia Power expects to request decertification of Plant Mitchell Unit 3 in connection with the triennial IRP to be filed in 2016. Georgia Power plans to continue to operate the unit as needed until the MATS rule becomes effective in April 2015.

(7) 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.

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

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

(10) Gulf Power intends to retire Plant Scholz by April 2015 and Unit 1 and 2 at Plant Smith by March 31, 2016.

(11) Mississippi Power has agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source the units at Plant Sweatt no later than December 2018. Mississippi Power also agreed that it would cease burning coal and other solid fuel at the units at Plant Watson and begin operating those units solely on natural gas no later than April 2015. See MANAGEMENT'S DISCUSSION AND ANALYSIS - FUTURE EARNINGS POTENTIAL - "Other Matters - Sierra Club Settlement" of Mississippi Power in Item 7 herein for additional information. See also Note 3 to the financial statements of Southern Company and Mississippi Power under "Other Matters - Sierra Club Settlement Agreement" in Item 8 herein.

(12) SEGCO is jointly-owned by Alabama Power and Georgia Power. See BUSINESS in Item 1 herein for additional information. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Georgia Power – Integrated Resource Plans" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Integrated Resource Plans" of Georgia Power in Item 7 herein. See also Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters – Georgia Power – Integrated Resource Plans" and "Retail Regulatory Matters – Integrated Resource Plans," respectively, in Item 8 herein for information on fuel switching at Plant Gaston.

(13) Mississippi Power placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service using natural gas on August 9, 2014 and continues to focus on completing the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities. The Kemper IGCC is expected to have an output capacity of 582 MW.

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

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

(16) Capacity shown represents 33 1/3% of total plant capacity. Georgia Power owns a 1/3 interest in the unit with 100% use of the unit from June through September. Progress Energy Florida operates the unit.

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

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

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

(20) 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 (which includes Adobe, Apex, Campo Verde, Cimarron, Granville, Macho Springs, and Spectrum) and 51% equity interest in SG2 Holdings (which includes Imperial Valley), Southern Power's equity portion of the total nameplate capacity is 358,452 KWs.

Except as discussed below under "Titles to Property," the principal plants and other important units of the traditional 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.

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, 2014, the unamortized portion of this cost was approximately $13.7 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 June 2013. The estimated capital cost of the mine and equipment is approximately $232.3 million, all of which has been incurred as of December 31, 2014. 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 2014, the maximum demand on the traditional operating companies, Southern Power, and SEGCO was 37,119,000 KWs and occurred on January 7, 2014. The all-time maximum demand of 38,777,000 KWs on the traditional 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 operating companies, Southern Power, and SEGCO in 2014 was 20.2%. See SELECTED FINANCIAL DATA in Item 6 herein for additional information.

Jointly-Owned Facilities

Alabama Power, Georgia Power, and Southern Power at December 31, 2014 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	Duke Energy Florida	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	—	—	—	—	—	—	—
Intercession City, FL	143	—	—	33.3	—	—	—	66.7	—	—	—	—
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 and Intercession City) 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 — Purchased Power Commitments" 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). In addition, Mississippi Power is constructing the Kemper IGCC and expects to sell a 15% ownership interest in the Kemper IGCC to SMEPA. See Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters - Georgia Power - Nuclear Construction" and "Retail Regulatory Matters - Nuclear Construction," respectively, in Item 8 herein. Also see Note 3 to the financial statements of each of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 herein for additional information.

Titles to Property

The traditional 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, (2) liens pursuant to the assumption of debt obligations by Mississippi Power in connection with the acquisition of Plant Daniel Units 3 and 4, and (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. See Note 6 to the financial statements of Southern Company, Georgia Power, Gulf Power, and Mississippi 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 of the financial statements of Southern Company and Mississippi Power under "Plant Daniel Revenue Bonds" in Item 8 herein for additional information. The traditional 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.

Item 3. LEGAL PROCEEDINGS

(1) United States of America v. Alabama Power (United States District Court for the Northern District of Alabama)

United States of America v. Georgia Power (United States District Court for the Northern District of Georgia)

See Note 3 to the financial statements of Southern Company and each traditional operating company under "Environmental Matters – New Source Review Actions" in Item 8 herein for information.

(2) Georgia Power et al. v. Westinghouse and Stone & Webster (United States District Court for the Southern District of Georgia Augusta Division)

Stone & Webster and Westinghouse v. Georgia Power et al. (United States District Court for the District of Columbia)

See Note 3 to the financial statements of Southern Company and Georgia Power under "Georgia Power – Nuclear Construction" and "Retail Regulatory Matters – Nuclear Construction," respectively, in Item 8 herein for information.

(3) Environmental Remediation

See Note 3 to the financial statements of Southern Company, Georgia Power, Gulf Power, and Mississippi Power under "Environmental Matters – Environmental Remediation" in Item 8 herein for information related to environmental remediation.

See Note 3 to the financial statements of each registrant in Item 8 herein for descriptions of additional 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, 2014.

Thomas A. Fanning
Chairman, President, Chief Executive Officer, and Director
Age 57
Elected in 2003. Chairman and Chief Executive Officer since December 2010 and President since August 2010. Previously served as Executive Vice President and Chief Operating Officer from February 2008 through July 2010.

Art P. Beattie
Executive Vice President and Chief Financial Officer
Age 60
Elected in 2010. Executive Vice President and Chief Financial Officer since August 2010. Previously served as Executive Vice President, Chief Financial Officer, and Treasurer of Alabama Power from February 2005 through August 2010.

W. Paul Bowers
Executive Vice President
Age 58
Elected in 2001. Executive Vice President since February 2008 and Chief Executive Officer, President, and Director of Georgia Power since January 2011 and Chief Operating Officer of Georgia Power from August 2010 to December 2010. Chairman of Georgia Power's Board of Directors since May 2014. Previously served as Executive Vice President and Chief Financial Officer of Southern Company from February 2008 to August 2010.

S. W. Connally, Jr.
President and Chief Executive Officer of Gulf Power
Age 45
Elected in 2012. 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 and Manager of Alabama Power's Plant Barry from August 2007 through July 2010.

Mark A. Crosswhite
Executive Vice President
Age 52
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 1, 2014. Previously served as Executive Vice President and Chief Operating Officer of Southern Company from July 2012 to March 2014, President, Chief Executive Officer, and Director of Gulf Power from January 2011 through June 2012, and Executive Vice President of External Affairs of Alabama Power from February 2008 through December 2010.

Kimberly S. Greene
Executive Vice President
Age 48

Elected in 2013. Executive Vice President and Chief Operating Officer since March 2014. 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 in a number of positions, most recently 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.

G. Edison Holland, Jr.
Executive Vice President
Age 62
Elected in 2001. Chairman, President, and Chief Executive Officer of Mississippi Power since May 2013 and Executive Vice President of Southern Company since April 2001. Previously served as Corporate Secretary of Southern Company from April 2005 until May 2013 and General Counsel of Southern Company from April 2001 until May 2013.

James Y. Kerr II
Executive Vice President and General Counsel
Age 50
Elected in 2014. 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
President and Chief Executive Officer of Southern Nuclear
Age 52
Elected in 2011. President and Chief Executive Officer of Southern Nuclear since July 2011. Before joining Southern Company, Mr. Kuczynski served at Exelon Corporation as the Senior Vice President of Engineering and Technical Services for Exelon Nuclear from February 2006 to June 2011.

Mark S. Lantrip
Executive Vice President
Age 60
Elected in 2014. President and Chief Executive Officer of SCS since March 2014. Previously served as Treasurer of Southern Company from October 2007 to February 2014, Executive Vice President of SCS from November 2010 to March 2014, and Senior Vice President of SCS from January 2010 to November 2010.

Christopher C. Womack
Executive Vice President
Age 56
Elected in 2008. Executive Vice President and President of External Affairs since January 2009.

The officers of Southern Company were elected for a term running from the first meeting of the directors following the last annual meeting (May 28, 2014) for one year or until their successors are elected and have qualified.

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, 2014.

Mark A. Crosswhite
Chairman, President, Chief Executive Officer, and Director
Age 52
Elected in 2014. President, Chief Executive Officer, and Director since March 1, 2014. Chairman since May 1, 2014. Previously served as Executive Vice President and Chief Operating Officer of Southern Company from July 2012 to March 2014, President, Chief Executive Officer, and Director of Gulf Power from January 2011 through June 2012, and Executive Vice President of External Affairs of Alabama Power from February 2008 through December 2010.

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer
Age 55
Elected in 2010. Executive Vice President, Chief Financial Officer, and Treasurer since August 2010. Previously served as Vice President and Chief Financial Officer of Gulf Power from May 2008 to August 2010.

Zeke W. Smith
Executive Vice President
Age 55
Elected in 2010. Executive Vice President of External Affairs since November 2010. Previously served as Vice President of Regulatory Services and Financial Planning from February 2005 to November 2010.

Steven R. Spencer
Executive Vice President
Age 59
Elected in 2001. Executive Vice President of the Customer Service Organization since February 2008.

James P. Heilbron
Senior Vice President and Senior Production Officer
Age 43
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 and Plant Manager of Georgia Power's Plant Wansley from March 2006 to July 2010.

The officers of Alabama Power were elected for a term running from the meeting of the directors held on April 25, 2014 for 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, 2014.

W. Paul Bowers
Chairman, President, Chief Executive Officer, and Director
Age 58
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. He previously served as Executive Vice President and Chief Financial Officer of Southern Company from February 2008 to August 2010.

W. Craig Barrs
Executive Vice President
Age 57
Elected in 2008. Executive Vice President of External Affairs since January 2010. Previously served as Senior Vice President of External Affairs from January 2009 to January 2010.

W. Ron Hinson
Executive Vice President, Chief Financial Officer, and Treasurer
Age 58
Elected in 2013. Executive Vice President, Chief Financial Officer, and Treasurer since March 2013. 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.

Joseph A. Miller
Executive Vice President
Age 53
Elected in 2009. Executive Vice President of Nuclear Development since May 2009. He also has served as Executive Vice President of Nuclear Development at Southern Nuclear from February 2006 to January 2013. He was elected as President of Nuclear Development at Southern Nuclear in January 2013.

Anthony L. Wilson
Executive Vice President
Age 50
Elected in 2007. Executive Vice President of Customer Service and Operations since January 2012. Previously served as Vice President of Transmission from November 2009 to January 2012 and Vice President of Distribution from February 2007 to November 2009.

Thomas P. Bishop
Senior Vice President, Chief Compliance Officer, General Counsel, and Corporate Secretary
Age 54
Elected in 2008. Corporate Secretary since April 2011 and Senior Vice President, Chief Compliance Officer, and General Counsel since September 2008.

John L. Pemberton
Senior Vice President and Senior Production Officer
Age 46
Elected in 2012. Senior Vice President and Senior Production Officer since July 2012. Previously served as Senior Vice President and General Counsel for SCS and Southern Nuclear from June 2010 to July 2012 and Vice President of Governmental Affairs for SCS from August 2006 to June 2010.

The officers of Georgia Power were elected for a term running from the meeting of the directors held on May 21, 2014 for one year or until their successors are elected and have qualified.

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, 2014.

G. Edison Holland, Jr.
Chairman, President, Chief Executive Officer, and Director
Age 62
Elected in 2013. Chairman, President, and Chief Executive Officer since May 2013 and Executive Vice President of Southern Company since April 2001. Previously served as Corporate Secretary of Southern Company from April 2005 until May 2013 and General Counsel of Southern Company from April 2001 until May 2013.

John W. Atherton
Vice President
Age 54
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.

Moses H. Feagin
Vice President, Treasurer, and Chief Financial Officer
Age 50
Elected in 2010. Vice President, Treasurer, and Chief Financial Officer since August 2010. Previously served as Vice President and Comptroller of Alabama Power from May 2008 to August 2010.

Jeff G. Franklin (1)
Vice President
Age 47
Elected in 2011. Vice President of Customer Services Organization since August 2011. Previously served as Georgia Power's Vice President of Governmental and Legislative Affairs from January 2011 to July 2011, and Vice President of Governmental and Regulatory Affairs from March 2009 to January 2011.

Mike A. Hazelton (2)
Vice President
Age 46
Elected in 2015. Vice President of Customer Services Organization effective April 2015. Previously served as Georgia Power's Senior Vice President of Marketing from January 2014 through March 2015, Vice President of Marketing from December 2011 to January 2014, Northeast Region Vice President from January 2011 to December 2011, and Land Acquisition Manger from June 2009 to January 2011.

R. Allen Reaves
Vice President
Age 55
Elected in 2010. Vice President and Senior Production Officer since August 2010. Previously served as Manager of Mississippi Power's Plant Daniel from September 2007 through July 2010.

Billy F. Thornton
Vice President
Age 54
Elected in 2012. Vice President of Legislative and Regulatory Affairs since October 2012. Previously served as Director of External Affairs from October 2011 until October 2012, Director of Marketing from March 2011 through October 2011, and Major Account Sales Manager from June 2006 to March 2011.

Emile J. Troxclair, III
Vice President
Age 57
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 for a term running from the meeting of the directors held on April 22, 2014 for one year or until their successors are elected and have qualified, except for Mr. Troxclair, whose election was effective on January 3, 2015.

(1) On February 16, 2015, Mr. Franklin was elected by the SCS Board of Directors as Vice President of Supply Chain effective March 28, 2015.

(2) On February 18, 2015, Mr. Hazelton was elected by the Mississippi Power Board of Directors as Vice President of Customer Services Organization effective April 1, 2015.

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 United States. The high and low stock prices as reported on the NYSE for each quarter of the past two years were as follows:

	High	Low
2014		
First Quarter	$ 44.00	$ 40.27
Second Quarter	46.81	42.55
Third Quarter	45.47	41.87
Fourth Quarter	51.28	43.55
2013		
First Quarter	$ 46.95	$ 42.82
Second Quarter	48.74	42.32
Third Quarter	45.75	40.63
Fourth Quarter	42.94	40.03

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, 2015: 136,875

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 operating companies to their stockholder(s) for the past two years were as follows:

Registrant	Quarter	2014	2013
		(in thousands)	
Southern Company	First	$ 450,991	$ 426,110
	Second	469,198	443,684
	Third	471,044	443,963
	Fourth	474,428	448,073
Alabama Power	First	137,390	132,290
	Second	137,390	132,290
	Third	137,390	132,290
	Fourth	137,390	247,290
Georgia Power	First	238,400	226,750
	Second	238,400	226,750
	Third	238,400	226,750
	Fourth	238,400	226,750
Gulf Power	First	30,800	28,850
	Second	30,800	28,850
	Third	30,800	28,950
	Fourth	30,800	28,750
Mississippi Power	First	54,930	44,190
	Second	54,930	44,190
	Third	54,930	44,190
	Fourth	54,930	44,190

In 2014 and 2013, Southern Power Company paid dividends to Southern Company as follows:

Registrant	Quarter	2014	2013
		(in thousands)	
Southern Power Company	First	$ 32,780	$ 32,280
	Second	32,780	32,280
	Third	32,780	32,280
	Fourth	32,780	32,280

The dividend paid per share of Southern Company's common stock was 50.75¢ for the first quarter 2014 and 52.50¢ each for the second, third, and fourth quarters of 2014. In 2013, Southern Company paid a dividend per share of 49¢ for the first quarter and 50.75¢ each for the second, third, and fourth quarters.

The traditional operating companies and Southern Power Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Southern Power Company's senior note indenture contains potential limitations on the payment of common stock dividends. At December 31, 2014, Southern Power Company was in compliance with the conditions of this senior note indenture and thus had no restrictions on its ability to pay common stock dividends. See Note 8 to the financial statements of Southern Company under "Common Stock Dividend Restrictions" and Note 6 to the financial statements of Southern Power under "Dividend Restrictions" in Item 8 herein for additional information regarding these restrictions.

(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 under the heading "Equity Compensation Plan Information" herein.

(b) Use of Proceeds

Not applicable.

(c) Issuer Purchases of Equity Securities

None.

Item 6. SELECTED FINANCIAL DATA

	Page
Southern Company. See "SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA"	II-120
Alabama Power. See "SELECTED FINANCIAL AND OPERATING DATA"	II-196
Georgia Power. See "SELECTED FINANCIAL AND OPERATING DATA"	II-279
Gulf Power. See "SELECTED FINANCIAL AND OPERATING DATA"	II-347
Mississippi Power. See "SELECTED FINANCIAL AND OPERATING DATA"	II-437
Southern Power. See "SELECTED FINANCIAL AND OPERATING DATA"	II-486

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

	Page
Southern Company. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS"	II-12
Alabama Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS,"	II-126
Georgia Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS,"	II-202
Gulf Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS,"	II-285
Mississippi Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS,"	II-354
Southern Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS,"	II-444

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 and Mississippi Power, and Note 8 to the financial statements of Southern Power in Item 8 herein.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO 2014 FINANCIAL STATEMENTS

	Page
The Southern Company and Subsidiary Companies:	
Management's Report on Internal Control Over Financial Reporting	II-8
Report of Independent Registered Public Accounting Firm	II-9
Consolidated Statements of Income for the Years Ended December 31, 2014, 2013, and 2012	II-45
Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2014, 2013, and 2012	II-46
Consolidated Statements of Cash Flows for the Years Ended December 31, 2014, 2013, and 2012	II-47
Consolidated Balance Sheets at December 31, 2014 and 2013	II-48
Consolidated Statements of Capitalization at December 31, 2014 and 2013	II-50
Consolidated Statements of Common Stockholders' Equity for the Years Ended December 31, 2014, 2013, and 2012	II-52
Notes to Financial Statements	II-53
Alabama Power:	
Management's Report on Internal Control Over Financial Reporting	II-123
Report of Independent Registered Public Accounting Firm	II-124
Statements of Income for the Years Ended December 31, 2014, 2013, and 2012	II-148
Statements of Comprehensive Income for the Years Ended December 31, 2014, 2013, and 2012	II-149
Statements of Cash Flows for the Years Ended December 31, 2014, 2013, and 2012	II-150
Balance Sheets at December 31, 2014 and 2013	II-151
Statements of Capitalization at December 31, 2014 and 2013	II-153
Statements of Common Stockholder's Equity for the Years Ended December 31, 2014, 2013, and 2012	II-154
Notes to Financial Statements	II-155
Georgia Power:	
Management's Report on Internal Control Over Financial Reporting	II-199
Report of Independent Registered Public Accounting Firm	II-200
Statements of Income for the Years Ended December 31, 2014, 2013, and 2012	II-228
Statements of Comprehensive Income for the Years Ended December 31, 2014, 2013, and 2012	II-229
Statements of Cash Flows for the Years Ended December 31, 2014, 2013, and 2012	II-230
Balance Sheets at December 31, 2014 and 2013	II-231
Statements of Capitalization at December 31, 2014 and 2013	II-233
Statements of Common Stockholder's Equity for the Years Ended December 31, 2014, 2013, and 2012	II-234
Notes to Financial Statements	II-235
Gulf Power:	
Management's Report on Internal Control Over Financial Reporting	II-282
Report of Independent Registered Public Accounting Firm	II-283
Statements of Income for the Years Ended December 31, 2014, 2013, and 2012	II-307
Statements of Comprehensive Income for the Years Ended December 31, 2014, 2013, and 2012	II-308
Statements of Cash Flows for the Years Ended December 31, 2014, 2013, and 2012	II-309
Balance Sheets at December 31, 2014 and 2013	II-310
Statements of Capitalization at December 31, 2014 and 2013	II-312
Statements of Common Stockholder's Equity for the Years Ended December 31, 2014, 2013, and 2012	II-313
Notes to Financial Statements	II-314

	Page
Mississippi Power:	
Management's Report on Internal Control Over Financial Reporting	II-350
Report of Independent Registered Public Accounting Firm	II-351
Statements of Operations for the Years Ended December 31, 2014, 2013, and 2012	II-387
Statements of Comprehensive Income (Loss) for the Years Ended December 31, 2014, 2013, and 2012	II-388
Statements of Cash Flows for the Years Ended December 31, 2014, 2013, and 2012	II-389
Balance Sheets at December 31, 2014 and 2013	II-390
Statements of Capitalization at December 31, 2014 and 2013	II-392
Statements of Common Stockholder's Equity for the Years Ended December 31, 2014, 2013, and 2012	II-393
Notes to Financial Statements	II-394
Southern Power and Subsidiary Companies:	
Management's Report on Internal Control Over Financial Reporting	II-440
Report of Independent Registered Public Accounting Firm	II-441
Consolidated Statements of Income for the Years Ended December 31, 2014, 2013, and 2012	II-462
Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2014, 2013, and 2012	II-463
Consolidated Statements of Cash Flows for the Years Ended December 31, 2014, 2013, and 2012	II-464
Consolidated Balance Sheets at December 31, 2014 and 2013	II-465
Consolidated Statements of Common Stockholders' Equity for the Years Ended December 31, 2014, 2013, and 2012	II-467
Notes to Financial Statements	II-468

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, Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power Company 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). Based upon these evaluations, the Chief Executive Officer and the Chief Financial Officer, in each case, concluded that the disclosure controls and procedures are effective.

Internal Control Over Financial Reporting.

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

Southern Company's Management's Report on Internal Control Over Financial Reporting is included on page II-8 of this Form 10-K.

Alabama Power's Management's Report on Internal Control Over Financial Reporting is included on page II-123 of this Form 10-K.

Georgia Power's Management's Report on Internal Control Over Financial Reporting is included on page II-199 of this Form 10-K.

Gulf Power's Management's Report on Internal Control Over Financial Reporting is included on page II-282 of this Form 10-K.

Mississippi Power's Management's Report on Internal Control Over Financial Reporting is included on page II-350 of this Form 10-K.

Southern Power's Management's Report on Internal Control Over Financial Reporting is included on page II-440 of this Form 10-K.

(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, and Southern Power as these companies are not accelerated filers or large accelerated filers.

(c) Changes in internal controls.

There have been no changes in Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, or Southern Power Company's 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) during the fourth quarter 2014 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, or Southern Power Company's internal control over financial reporting.

Item 9B. OTHER INFORMATION

None.

THE SOUTHERN COMPANY
AND SUBSIDIARY COMPANIES

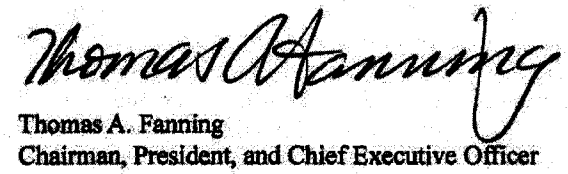
FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Southern Company and Subsidiary Companies 2014 Annual Report

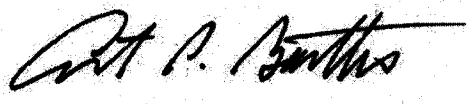
The management of The Southern Company (Southern Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, 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, 2014.

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, 2014. Deloitte & Touche LLP's report on Southern Company's internal control over financial reporting is included herein.



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



Art P. Beattie
Executive Vice President and Chief Financial Officer

March 2, 2015

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, 2014 and 2013, 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, 2014. We also have audited the Company's internal control over financial reporting as of December 31, 2014, 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-45 to II-118) referred to above present fairly, in all material respects, the financial position of The Southern Company and Subsidiary Companies as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, 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, 2014, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Deloitte & Touche LLP

Atlanta, Georgia
March 2, 2015

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 for Georgia Power for the years 2014 through 2016
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
APA	Asset purchase agreement
ASC	Accounting Standards Codification
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
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FFB	Federal Financing Bank
GAAP	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 account for use in mitigating future rate impacts for customers
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MPUS	Mississippi Public Utilities Staff
MW	Megawatt
NCCR	Georgia Power's Nuclear Construction Cost Recovery
NDR	Alabama Power's Natural Disaster Reserve
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 operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement

Term	Meaning
PSC	Public Service Commission
Rate CNP	Alabama Power's Rate Certificated New Plant
Rate CNP Environmental	Alabama Power's Rate Certificated New Plant Environmental
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 natural disaster reserve rate
Rate RSE	Alabama Power's rate stabilization and equalization plan
ROE	Return on equity
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, 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
Southern Company system	The Southern Company, the traditional operating companies, Southern Power, SEGCO, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power

OVERVIEW

Business Activities

The Southern Company (Southern Company or the Company) is a holding company that owns all of the common stock of the Southern Company system, which consists of the traditional operating companies, Southern Power, and other direct and indirect subsidiaries. The primary business of the Southern Company system is electricity sales by the traditional operating companies and Southern Power. The four traditional operating companies 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.

Many factors affect the opportunities, challenges, and risks of the Southern Company system's electricity business. These factors include the traditional operating companies' ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, fuel, capital expenditures, including new plants, and restoration following major storms. Subsidiaries of Southern Company are constructing Plant Vogtle Units 3 and 4 and the Kemper IGCC. Georgia Power has a 45.7% ownership interest in Plant Vogtle Units 3 and 4, each with approximately 1,100 MWs, and Mississippi Power is ultimately expected to hold an 85% ownership interest in the 582-MW Kemper IGCC.

Each of the traditional operating companies 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 Southern Company system for the foreseeable future. See Note 3 to the financial statements under "Retail Regulatory Matters" and "Integrated Coal Gasification Combined Cycle" for additional information.

Another major factor is the profitability of the competitive market-based wholesale generating business. Southern Power's strategy is to acquire, construct, and sell power plants, including renewable energy projects, and to enter into PPAs primarily with investor-owned utilities, independent power producers, municipalities, and electric cooperatives.

Southern Company's other business activities include investments in leveraged lease projects and telecommunications. Management continues to evaluate the contribution of each of these activities to total shareholder return and may pursue acquisitions and dispositions accordingly.

Key Performance Indicators

In striving to achieve superior risk-adjusted returns while providing cost-effective energy to more than four million customers, the Southern Company system continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, 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.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The Southern Company system's fossil/hydro 2014 Peak Season EFOR was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The Southern Company system's performance for 2014 was better than the target for these reliability measures. Primarily as a result of charges for estimated probable losses related to construction of the Kemper IGCC, Southern Company's EPS for 2014 did not meet the target on a GAAP basis. See RESULTS OF OPERATIONS – "Estimated Loss on Kemper IGCC" and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

Excluding the charges for estimated probable losses related to construction of the Kemper IGCC and the 2015 Mississippi Supreme Court decision, Southern Company's 2014 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2014 Target Performance	2014 Actual Performance
System Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season System EFOR — fossil/hydro	5.51% or less	1.93%
Basic EPS — As Reported	$2.72-$2.80	$2.19
Kemper IGCC Impacts		$0.61
EPS, excluding items*		$2.80

* Does not reflect EPS as calculated in accordance with GAAP. The non-GAAP measure of EPS, excluding estimated probable losses relating to Mississippi Power's construction of the Kemper IGCC and the 2015 Mississippi Supreme Court decision, is calculated by excluding from EPS, as determined in accordance with GAAP, the following items: (1) estimated probable losses of $536 million after-tax, or $0.59 per share, relating to Mississippi Power's construction of the Kemper IGCC and (2) an aggregate of $17 million after-tax, or $0.02 per share, relating to the reversal of previously recognized revenues recorded in 2014 and 2013 and the recognition of carrying costs associated with the 2015 Mississippi Supreme Court decision which reversed the Mississippi PSC's March 2013 rate order related to the Kemper IGCC. The estimated probable losses relating to the construction of the Kemper IGCC significantly impacted the presentation of EPS in the table above, and any similar charges are items that may occur with uncertain frequency in the future. In addition, neither the estimated probable losses relating to the construction of the Kemper IGCC nor the 2015 Mississippi Supreme Court decision were anticipated or incorporated in the assumptions used to develop the EPS target performance for 2014 reflected in the table above. See RESULTS OF OPERATIONS – "Estimated Loss on Kemper IGCC" and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information on the estimated probable losses relating to the Kemper IGCC and the 2015 Mississippi Supreme Court decision. Southern Company management uses the non-GAAP measure of EPS, excluding these items, to evaluate the performance of Southern Company's ongoing business activities and its 2014 performance on a basis consistent with the assumptions used in developing the 2014 performance targets and to compare certain results to prior periods. Southern Company believes this presentation is useful to investors by providing additional information for purposes of evaluating the performance of Southern Company's business activities. This presentation is not meant to be considered a substitute for financial measures prepared in accordance with GAAP.

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

Earnings

Southern Company's net income after dividends on preferred and preference stock of subsidiaries was $2.0 billion in 2014, an increase of $319 million, or 19.4%, from the prior year. The increase was primarily related to an increase in retail revenues due to retail base rate increases, as well as colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013. The increase in net income was also the result of lower pre-tax charges of $868 million ($536 million after tax) recorded in 2014 compared to pre-tax charges of $1.2 billion ($729 million after tax) recorded in 2013 for revisions of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC. These increases were partially offset by increases in non-fuel operations and maintenance expenses.

Southern Company's net income after dividends on preferred and preference stock of subsidiaries was $1.6 billion in 2013, a decrease of $706 million, or 30.0%, from the prior year. The decrease was primarily the result of pre-tax charges of $1.2 billion ($729 million after-tax) for revisions of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC. Also contributing to the decrease in net income were increases in depreciation and amortization and non-fuel operations and maintenance expenses, partially offset by increases in retail revenues and AFUDC.

Basic EPS was $2.19 in 2014, $1.88 in 2013, and $2.70 in 2012. Diluted EPS, which factors in additional shares related to stock-based compensation, was $2.18 in 2014, $1.87 in 2013, and $2.67 in 2012. EPS for 2014 was negatively impacted by $0.06 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 $2.0825 in 2014, $2.0125 in 2013, and $1.9425 in 2012. In January 2015, Southern Company declared a quarterly dividend of 52.50 cents per share. This is the 269th consecutive quarter that Southern Company has paid a dividend equal to or higher than the previous quarter. For 2014, the actual dividend payout ratio was 95%, while the payout ratio of net income excluding estimated probable losses relating to Mississippi Power's construction of the Kemper IGCC and the 2015 Mississippi Supreme Court decision was 74%.

RESULTS OF OPERATIONS

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

	Amount		
	2014	2013	2012
		(in millions)	
Electricity business	$ 1,969	$ 1,652	$ 2,321
Other business activities	(6)	(8)	29
Net Income	$ 1,963	$ 1,644	$ 2,350

Electricity Business

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

A condensed statement of income for the electricity business follows:

	Amount	Increase (Decrease) from Prior Year	
	2014	2014	2013
		(in millions)	
Electric operating revenues	$ 18,406	$ 1,371	$ 557
Fuel	6,005	495	453
Purchased power	672	211	(83)
Other operations and maintenance	4,259	481	83
Depreciation and amortization	1,929	43	114
Taxes other than income taxes	979	47	20
Estimated loss on Kemper IGCC	868	(312)	1,180
Total electric operating expenses	14,712	965	1,767
Operating income	3,694	406	(1,210)
Allowance for equity funds used during construction	245	55	47
Interest income	18	—	(4)
Interest expense, net of amounts capitalized	794	6	(32)
Other income (expense), net	(73)	(18)	2
Income taxes	1,053	118	(465)
Net income	2,037	319	(668)
Dividends on preferred and preference stock of subsidiaries	68	2	1
Net income after dividends on preferred and preference stock of subsidiaries	$ 1,969	$ 317	$ (669)

Electric Operating Revenues

Electric operating revenues for 2014 were $18.4 billion, reflecting a $1.4 billion increase from 2013. Details of electric operating revenues were as follows:

	Amount	
	2014	2013
	(in millions)	
Retail — prior year	$ 14,541	$ 14,187
Estimated change resulting from —		
Rates and pricing	300	137
Sales growth (decline)	35	(2)
Weather	236	(40)
Fuel and other cost recovery	438	259
Retail — current year	15,550	14,541
Wholesale revenues	2,184	1,855
Other electric operating revenues	672	639
Electric operating revenues	$ 18,406	$ 17,035
Percent change	8.0%	3.4%

Retail revenues increased $1.0 billion, or 6.9%, in 2014 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 2014 was primarily due to increased revenues at Georgia Power related to base tariff increases effective January 1, 2014, as approved by the Georgia PSC in the 2013 ARP, and increases in collections for financing costs related to the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff, as well as higher contributions from market-driven rates from commercial and industrial customers. Also contributing to the increase were increased revenues at Alabama Power associated with Rate CNP Environmental primarily resulting from the inclusion of pre-2005 environmental assets and increased revenues at Gulf Power primarily resulting from a retail base rate increase and an increase in the environmental cost recovery clause rate, both effective January 2014, as approved by the Florida PSC.

Retail revenues increased $354 million, or 2.5%, in 2013 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 2013 was primarily due to base tariff increases at Georgia Power effective April 1, 2012 and January 1, 2013, as approved by the Georgia PSC, related to placing new generating units at Plant McDonough-Atkinson in service and collecting financing costs related to the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff, as well as higher contributions from market-driven rates from commercial and industrial customers.

See Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Alabama Power – Rate CNP," "– Georgia Power – Rate Plans," and "– Gulf Power – Retail Base Rate Case" and "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2015 Mississippi Supreme Court Decision" 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 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 purchased power costs, and do not affect net income. The traditional operating companies may also have one or more regulatory mechanisms to recover other costs such as environmental, storm damage, new plants, and PPAs.

Wholesale revenues consist of PPAs with investor-owned utilities and electric cooperatives and short-term opportunity sales. Wholesale revenues from PPAs (other than solar PPAs) have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and 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 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. Wholesale 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 revenues from power sales were as follows:

	2014	2013	2012
		(in millions)	
Capacity and other	$ 974	$ 971	$ 899
Energy	1,210	884	776
Total	$ 2,184	$ 1,855	$ 1,675

In 2014, wholesale revenues increased $329 million, or 17.7%, as compared to the prior year due to a $326 million increase in energy revenues and a $3 million increase in capacity revenues. The increase in energy revenues was primarily related to increased revenue under existing contracts as well as new solar PPAs and requirements contracts primarily at Southern Power, increased demand resulting from colder weather in the first quarter 2014 as compared to the corresponding period in 2013, and an increase in the average cost of natural gas. The increase in capacity revenues was primarily due to wholesale base rate increases at Mississippi Power, partially offset by a decrease in capacity revenues primarily due to lower customer demand and the expiration of certain requirements contracts at Southern Power.

In 2013, wholesale revenues increased $180 million, or 10.7%, as compared to the prior year due to a $108 million increase in energy revenues and a $72 million increase in capacity revenues. The increase in energy revenues was primarily related to an increase in the average price of energy and new solar contracts served by Southern Power's Plants Campo Verde and Spectrum, which began in 2013, partially offset by a decrease in volume related to milder weather as compared to the prior year. The increase in capacity revenues was primarily due to a new PPA served by Southern Power's Plant Nacogdoches, which began in June 2012, and an increase in capacity revenues under existing PPAs.

Other Electric Revenues

Other electric revenues increased $33 million, or 5.2%, and $23 million, or 3.7%, in 2014 and 2013, respectively, as compared to the prior years. The 2014 increase was primarily due to increases in open access transmission tariff revenues and transmission service revenues primarily at Alabama Power and Georgia Power, an increase in co-generation steam revenues at Alabama Power, increases in outdoor lighting and solar application fee revenues at Georgia Power, as well as an increase in franchise fees at Gulf Power. The 2013 increase in other electric revenues was primarily a result of increases in transmission revenues related to the open access transmission tariff and rents from electric property related to pole attachments.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2014 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2014	2014	2013	2014	2013*
	(in billions)				
Residential	53.4	5.5%	0.2 %	—%	(0.3)%
Commercial	53.2	1.3	(0.9)	(0.4)	(0.1)
Industrial	54.1	3.3	1.5	3.3	1.5
Other	0.9	0.9	(1.8)	0.7	(1.9)
Total retail	161.6	3.3	0.3	0.9%	0.4 %
Wholesale	32.8	21.7	(2.2)		
Total energy sales	194.4	6.0%	(0.1)%		

* In the first quarter 2012, Georgia Power began using new actual advanced meter data to compute unbilled revenues. The weather-adjusted KWH sales variances shown above reflect an adjustment to the estimated allocation of Georgia Power's unbilled January 2012 KWH sales among customer classes that is consistent with the actual allocation in 2013. Without this adjustment, 2013 weather-adjusted residential KWH sales decreased 0.5% as compared to 2012 while 2013 weather-adjusted commercial KWH sales increased 0.2% as compared to 2012.

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 5.2 billion KWHs in 2014 as compared to the prior year. This increase was primarily the result of colder weather in the first quarter 2014 and warmer weather in the second and third quarters

2014 as compared to the corresponding periods in 2013 and customer growth, partially offset by a decrease in customer usage. The increase in industrial KWH energy sales was primarily due to increased sales in the primary metals, chemicals, paper, non-manufacturing, transportation, and stone, clay, and glass sectors. Weather-adjusted commercial KWH energy sales decreased primarily due to decreased customer usage, partially offset by customer growth. Weather-adjusted residential KWH energy sales were flat compared to the prior year as a result of customer growth offset by decreased customer usage. Household income, one of the primary drivers of residential customer usage, was flat in 2014.

Retail energy sales increased 403 million KWHs in 2013 as compared to the prior year. This increase was primarily the result of customer growth, partially offset by milder weather and a decrease in customer usage. Weather-adjusted residential and commercial energy sales remained relatively flat compared to the prior year with a decrease in customer usage, offset by customer growth. The increase in industrial energy sales was primarily due to increased demand in the paper, primary metals, and stone, clay, and glass sectors.

Wholesale energy sales increased 5.8 billion KWHs in 2014 as compared to the prior year. The increase was primarily related to higher natural gas prices and increased energy sales as a result of colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013. Wholesale energy sales decreased 619 million KWHs in 2013 as compared to the prior year. The decrease was primarily related to lower customer demand resulting from milder weather as compared to the prior year.

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:

	2014	2013	2012
Total generation *(billions of KWHs)*	**191**	179	175
Total purchased power *(billions of KWHs)*	**12**	12	16
Sources of generation *(percent)* —			
Coal	**42**	39	38
Nuclear	**16**	17	18
Gas	**39**	40	42
Hydro	**3**	4	2
Cost of fuel, generated *(cents per net KWH)* —			
Coal	**3.81**	4.01	3.96
Nuclear	**0.87**	0.87	0.83
Gas	**3.63**	3.29	2.86
Average cost of fuel, generated *(cents per net KWH)*	**3.25**	3.17	2.93
Average cost of purchased power *(cents per net KWH)**	**7.13**	5.27	4.45

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

In 2014, total fuel and purchased power expenses were $6.7 billion, an increase of $706 million, or 11.8%, as compared to the prior year. The increase was primarily the result of a $422 million increase in the volume of KWHs generated primarily due to increased demand resulting from colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 and a $286 million increase in the average cost of fuel and purchased power primarily due to higher natural gas prices.

In 2013, total fuel and purchased power expenses were $6.0 billion, an increase of $370 million, or 6.6%, as compared to the prior year. This increase was primarily the result of a $446 million increase in the average cost of fuel and purchased power primarily due to higher natural gas prices and a $113 million increase in the volume of KWHs generated, partially offset by a $189 million decrease in the volume of KWHs purchased as the marginal cost of generation available was lower than the market cost of available energy.

Fuel and purchased power energy transactions at the traditional operating companies are generally offset by fuel revenues and do not have a significant impact on net income. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Retail 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 2014, fuel expense was $6.0 billion, an increase of $495 million, or 9.0%, as compared to the prior year. The increase was primarily due to a 12.7% increase in the volume of KWHs generated by coal, a 10.3% increase in the average cost of natural gas per KWH generated, and a 30.7% decrease in the volume of KWHs generated by hydro facilities resulting from less rainfall, partially offset by a 5.0% decrease in the average cost of coal per KWH generated.

In 2013, fuel expense was $5.5 billion, an increase of $453 million, or 9.0%, as compared to the prior year. The increase was primarily due to a 15.0% increase in the average cost of natural gas per KWH generated, partially offset by a 125.9% increase in the volume of KWHs generated by hydro facilities resulting from greater rainfall.

Purchased Power

In 2014, purchased power expense was $672 million, an increase of $211 million, or 45.8%, as compared to the prior year. The increase was primarily due to a 35.3% increase in the average cost per KWH purchased.

In 2013, purchased power expense was $461 million, a decrease of $83 million, or 15.3%, as compared to the prior year. The decrease was primarily due to a 25.9% decrease in the volume of KWHs purchased as the marginal cost of generation available was lower than the market cost of available energy, partially offset by an 18.4% increase in the average cost per KWH purchased.

Energy purchases will vary depending on demand for energy within the Southern Company system's 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.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses increased $481 million, or 12.7%, in 2014 as compared to the prior year. The increase was primarily related to increases of $149 million in scheduled outage costs at generation facilities, $103 million in other generation expenses primarily related to commodity and labor costs, $103 million in transmission and distribution costs primarily related to overhead line maintenance, $42 million in net employee compensation and benefits including pension costs, and $31 million in customer accounts, service, and sales costs primarily related to customer incentive and demand-side management programs.

Other operations and maintenance expenses increased $83 million, or 2.2%, in 2013 as compared to the prior year. Other operations and maintenance expenses in 2013 were significantly below normal levels as a result of cost containment efforts undertaken primarily at Georgia Power to offset the impact of significantly milder than normal weather conditions. Administrative and general expenses increased $63 million primarily as a result of an increase in pension costs. Transmission and distribution expenses increased $27 million primarily due to increases at Georgia Power in transmission system load expense resulting from billing adjustments with integrated transmission system owners.

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 $43 million, or 2.3%, in 2014 as compared to the prior year primarily due to increases in depreciation rates related to environmental assets and the amortization of certain regulatory assets at Alabama Power and the completion of the amortization of certain regulatory liabilities at Georgia Power. Also contributing to the increase were increases at Southern Power in plant in service related to the addition of solar facilities in 2013 and 2014, an increase related to equipment retirements resulting from accelerated outage work, and additional component depreciation as a result of increased production. These increases were largely offset by the amortization of $120 million of the regulatory liability for other cost of removal obligations at Alabama Power. See Note 3 to the financial statements under "Retail Regulatory Matters – Alabama Power – Rate CNP" and "– Cost of Removal Accounting Order" for additional information.

Depreciation and amortization increased $114 million, or 6.4%, in 2013 as compared to the prior year primarily due to additional plant in service related to the completion of Georgia Power's Plant McDonough-Atkinson Units 5 and 6 in April 2012 and October 2012, respectively, and six Southern Power plants between June 2012 and October 2013, certain coal unit retirement

decisions (with respect to the portion of such units dedicated to wholesale service) at Georgia Power, and additional transmission and distribution projects. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Georgia Power – Integrated Resource Plans" for additional information on Georgia Power's unit retirement decisions. These increases were partially offset by a net reduction in amortization primarily related to amortization of a regulatory liability for state income tax credits at Georgia Power and by the deferral of certain expenses under an accounting order at Alabama Power. See Note 3 to the financial statements under "Retail Regulatory Matters – Alabama Power – Compliance and Pension Cost Accounting Order" for additional information on Alabama Power's accounting order.

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 $47 million, or 5.0%, in 2014 as compared to the prior year primarily due to increases of $34 million in municipal franchise fees related to higher retail revenues in 2014 and $16 million in payroll taxes primarily related to higher employee benefits.

Taxes other than income taxes increased $20 million, or 2.2%, in 2013 as compared to the prior year primarily due to increases in property taxes.

Estimated Loss on Kemper IGCC

In 2014 and 2013, estimated probable losses on the Kemper IGCC of $868 million and $1.2 billion, 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 (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). See FUTURE EARNINGS POTENTIAL – "Construction Program" herein and 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 $55 million, or 28.9%, in 2014 as compared to the prior year primarily due to additional capital expenditures at the traditional operating companies, primarily related to environmental and transmission projects, as well as Mississippi Power's Kemper IGCC.

AFUDC equity increased $47 million, or 32.9%, in 2013 as compared to the prior year primarily due to an increase in CWIP related to Mississippi Power's Kemper IGCC and increased capital expenditures at Alabama Power, partially offset by the completion of Georgia Power's Plant McDonough-Atkinson Units 5 and 6 in 2012.

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 $6 million, or 0.8%, in 2014 as compared to the prior year primarily due to a higher amount of outstanding long-term debt and an increase in interest expense resulting from the deposits received by Mississippi Power in January and October 2014 related to SMEPA's pending purchase of an undivided interest in the Kemper IGCC, partially offset by a decrease in interest expense related to the refinancing of long-term debt at lower rates and an increase in capitalized interest. See Note 6 to the financial statements for additional information.

Interest expense, net of amounts capitalized decreased $32 million, or 3.9%, in 2013 as compared to the prior year primarily due to lower interest rates, the timing of issuances and redemptions of long-term debt, an increase in capitalized interest primarily resulting from AFUDC debt associated with Mississippi Power's Kemper IGCC, and an increase in capitalized interest associated with the construction of Southern Power's Plants Campo Verde and Spectrum. These decreases were partially offset by a decrease in capitalized interest resulting from the completion of Southern Power's Plants Nacogdoches and Cleveland, a reduction in AFUDC debt due to the completion of Georgia Power's Plant McDonough-Atkinson Units 5 and 6, and the conclusion of certain state and federal tax audits in 2012.

Other Income (Expense), Net

Other income (expense), net decreased $18 million, or 32.7%, in 2014 as compared to the prior year primarily due to an $8 million decrease in wholesale operating fee revenue at Georgia Power and $7 million associated with Mississippi Power's settlement with the Sierra Club. See Note 3 to the financial statements under "Other Matters – Sierra Club Settlement Agreement" for additional information.

Income Taxes

Income taxes increased $118 million, or 12.6%, in 2014 as compared to the prior year primarily due to higher pre-tax earnings, partially offset by an increase in non-taxable AFUDC equity and an increase in tax benefits related to federal ITCs.

Income taxes decreased $465 million, or 33.2%, in 2013 as compared to the prior year primarily due to lower pre-tax earnings, an increase in tax benefits recognized from ITCs at Southern Power, and a net increase in non-taxable AFUDC equity, partially offset by a decrease in state income tax credits, primarily at Georgia Power.

Other Business Activities

Southern Company's other business activities include the parent company (which does not allocate operating expenses to business units), investments in leveraged lease projects, and telecommunications. These businesses are classified in general categories and may comprise one or both of the following subsidiaries: Southern Company Holdings, Inc. (Southern Holdings) invests in various projects, including leveraged lease projects, and SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast.

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

	Amount	Increase (Decrease) from Prior Year	
	2014	2014	2013
		(in millions)	
Operating revenues	$ 61	$ 9	$ (7)
Other operations and maintenance	95	27	(9)
Depreciation and amortization	16	1	—
Taxes other than income taxes	2	—	—
Total operating expenses	113	28	(9)
Operating income (loss)	(52)	(19)	2
Interest income	1	—	(17)
Other income (expense), net	10	36	(45)
Interest expense	41	5	(3)
Income taxes	(76)	10	(20)
Net income (loss)	$ (6)	$ 2	$ (37)

Operating Revenues

Southern Company's non-electric operating revenues for these other business activities increased $9 million, or 17.3%, in 2014 as compared to the prior year. The increase was primarily related to higher operating revenues at Southern Holdings, partially offset by decreases in revenues at SouthernLINC Wireless related to lower average per subscriber revenue and fewer subscribers due to continued competition in the industry. Non-electric operating revenues for these other businesses decreased $7 million, or 11.9%, in 2013 as compared to the prior year. The decrease was primarily the result of decreases in revenues at SouthernLINC Wireless related to lower average per subscriber revenue and fewer subscribers due to continued competition in the industry.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses for these other business activities increased $27 million, or 39.7%, in 2014 as compared to the prior year. The increase was primarily due to insurance proceeds received in 2013 related to a litigation settlement with MC Asset Recovery, LLC and higher operating expenses at Southern Holdings. Other operations and maintenance expenses for these other business activities decreased $9 million, or 11.7%, in 2013 as compared to the prior year. The decrease

was primarily related to lower operating expenses at SouthernLINC Wireless and decreases in consulting and legal fees, partially offset by higher operating expenses at Southern Holdings and a decrease in the amount of insurance proceeds received in 2013 related to a litigation settlement with MC Asset Recovery, LLC as compared to the amount received in 2012. See Note 3 to the financial statements under "Insurance Recovery" for additional information related to the litigation settlement with MC Asset Recovery, LLC.

Interest Income

Interest income for these other business activities decreased $17 million in 2013 as compared to the prior year primarily due to the conclusion of certain federal income tax audits in 2012.

Other Income (Expense), Net

Other income (expense), net for these other business activities increased $36 million in 2014 as compared to the prior year. The increase was primarily due to the restructuring of a leveraged lease investment in the first quarter of 2013 and a decrease in charitable contributions in 2014. Other income (expense), net for these other business activities decreased $45 million in 2013 as compared to the prior year. The decrease was primarily due to the restructuring of a leveraged lease investment and an increase in charitable contributions.

Southern Company has several leveraged lease agreements 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. See Note 1 under "Leveraged Leases" for additional information.

Interest Expense

Interest expense for these other business activities increased $5 million, or 13.9%, in 2014 as compared to the prior year. The increase was primarily due to a higher amount of outstanding long-term debt, partially offset by the refinancing of long-term debt at lower rates.

Income Taxes

Income taxes for these other business activities increased $10 million, or 11.6%, in 2014 and decreased $20 million, or 30.3%, in 2013 as compared to the prior year primarily as a result of changes in pre-tax earnings (losses).

Effects of Inflation

The traditional operating companies 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 operating companies operate as vertically integrated utilities providing electricity to customers within their service areas in the Southeast. Prices for electricity provided to retail customers are set by state PSCs 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. Southern Power continues to focus on long-term capacity contracts, optimized by limited energy trading activities. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric 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 business of selling electricity. These factors include the traditional operating companies' 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 the completion and subsequent operation of the Kemper IGCC and Plant Vogtle Units 3 and 4 as well as other ongoing construction projects. Other major factors include the profitability of the competitive wholesale business and successfully expanding investments in renewable energy projects. Future earnings for the electricity business in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, new energy contracts 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 service territory. In addition, the level of future earnings for the wholesale business also depends on numerous factors including creditworthiness of customers, total generating capacity available and related costs, future acquisitions and construction of generating facilities, including the impact of ITCs, and the successful remarketing of capacity as current contracts expire. Changes in regional and global economic conditions may impact sales for the traditional operating companies and Southern Power, as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

As part of its ongoing effort to adapt to changing market conditions, Southern Company continues to evaluate and consider a wide array of potential business strategies. These strategies may include business combinations, partnerships, and acquisitions involving other utility or non-utility businesses or properties, disposition of certain assets, 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.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis or through market-based contracts. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. 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.

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against Alabama Power and Georgia Power alleging violations of the New Source Review provisions of the Clean Air Act at certain coal-fired electric generating units, including units co-owned by Gulf Power and Mississippi Power. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. See Note 3 to the financial statements under "Environmental Matters – New Source Review Actions" for additional information. The ultimate outcome of these matters cannot be determined at this time.

Environmental Statutes and Regulations

General

The 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. 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; 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 2014, the traditional operating companies had invested approximately $10.6 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $1.1 billion, $0.7 billion, and $0.3 billion for 2014, 2013, and 2012, respectively. The Southern Company system expects that capital expenditures to comply with environmental statutes and regulations will total approximately $2.1 billion from 2015 through 2017, with annual totals of approximately $1.0 billion, $0.5 billion, and $0.6 billion for 2015, 2016, and 2017, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information.

The 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 and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the 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

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 – Alabama Power – Environmental Accounting Order" and "Retail Regulatory Matters – Georgia Power – Integrated Resource Plans" herein and Note 3 to the financial statements under "Other Matters – Sierra Club Settlement Agreement" for additional information on planned unit retirements and fuel conversions at Alabama Power, Georgia Power, and Mississippi Power.

Compliance with any new federal or state legislation or regulations relating to air quality, water, CCR, global climate change, 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 electric utilities' operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the electric utilities' 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 Southern Company system. Since 1990, the electric utilities have spent approximately $9.5 billion in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2012, the EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015 up to April 16, 2016 for affected units for which extensions have been granted. On November 25, 2014, the U.S. Supreme Court granted a petition for review of the final MATS rule.

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 more stringent eight-hour ozone NAAQS, which it began to implement in 2011. In 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone NAAQS. The only area within the traditional operating companies' service territory designated as an ozone nonattainment area is a 15-county area within metropolitan Atlanta. On December 17, 2014, the EPA published a proposed rule to further reduce the current eight-hour ozone standard. The EPA is required by federal court order to complete this rulemaking by October 1, 2015. Finalization of a lower eight-hour ozone standard could result in the designation of new ozone nonattainment areas within the traditional operating companies' service territory.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the traditional operating companies' service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS and, with the exception of the Atlanta area, the EPA has officially redesignated former nonattainment areas within the service territory as attainment for these standards. A redesignation request for the Atlanta area is pending with the EPA. In 2012, the EPA issued a final rule that increases the stringency of the annual fine particulate matter standard. The EPA promulgated final designations for the 2012 annual standard on December 18, 2014, and no new nonattainment areas were designated within the traditional operating companies' service territory. The EPA has, however, deferred designation decisions for certain areas in Alabama, Florida, and Georgia, so future nonattainment designations in these areas are possible.

Final revisions to the NAAQS for sulfur dioxide (SO_2), which established a new one-hour standard, became effective in 2010. No areas within the Southern Company system's service territory have been designated as nonattainment under this rule. However, the EPA has announced plans to make additional designation decisions for SO_2 in the future, which could result in nonattainment designations for areas within the Southern Company system's service territory. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

On February 13, 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 March 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, units co-owned with Mississippi Power, and units owned by SEGCO, which is jointly owned by Alabama Power and Georgia Power.

Each of the states in which the Southern Company system has fossil generation is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I beginning in 2015 and Phase II beginning in 2017. In 2012, the U.S. Court of

Appeals for the District of Columbia Circuit vacated CSAPR in its entirety, but on April 29, 2014, the U.S. Supreme Court overturned that decision and remanded the case back to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The U.S. Court of Appeals for the District of Columbia Circuit granted the EPA's motion to lift the stay of the rule, and the first phase of CSAPR took effect on January 1, 2015.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology to certain sources, including fossil fuel-fired generating facilities, built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter.

In 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units), during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

In February 2013, the EPA proposed a rule that would require certain states to revise 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 EPA proposed to supplement the 2013 proposed rule on September 17, 2014, making it more stringent. The EPA has entered into a settlement agreement requiring it to finalize the proposed rule by May 22, 2015. The proposed rule would require states subject to the rule (including Alabama, Florida, Georgia, Mississippi, and North Carolina) to revise their SSM provisions within 18 months after issuance of the final 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. As part of this strategy, certain of the traditional operating companies have developed a compliance plan for the MATS rule which includes reliance on existing emission control technologies, the construction of baghouses to provide an additional level of control on the emissions of mercury and particulates from certain generating units, the use of additives or other injection technology, the use of existing or additional natural gas capability, and unit retirements. Additionally, certain transmission system upgrades are required. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, the Alabama opacity rule, CSAPR, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the Southern Company system cannot be determined at this time and will depend on the specific provisions of the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. These regulations could result in significant additional 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.

In addition to the federal air quality laws described above, Georgia Power is also subject to the requirements of the 2007 State of Georgia Multi-Pollutant Rule. The Multi-Pollutant Rule, as amended, is designed to reduce emissions of mercury, SO_2, and nitrogen oxide state-wide by requiring the installation of specified control technologies at certain coal-fired generating units by specific dates between December 31, 2008 and April 16, 2015. A companion rule requires a 95% reduction in SO_2 emissions from the controlled units on the same or similar timetable. Through December 31, 2014, Georgia Power had installed the required controls on 14 of its coal-fired generating units with two additional projects to be completed before the unit-specific installation deadlines.

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 on October 14, 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

In June 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing revised technology-based limits for certain wastestreams from steam electric power plants and best management practices for CCR surface impoundments. The EPA has entered into a consent decree requiring it to finalize revisions to the steam electric effluent guidelines by September 30, 2015. The ultimate impact of the rule will also depend on the specific technology requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

On April 21, 2014, the EPA and the U.S. Army Corps of Engineers jointly published a proposed rule to revise the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs, which would significantly expand the scope of federal jurisdiction under the CWA. In addition, the rule as proposed could have significant impacts on economic development projects

which could affect customer demand growth. The ultimate impact of the proposed rule will depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time. If finalized as proposed, 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.

These proposed and final water quality regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through PPAs.

Coal Combustion Residuals

The traditional operating companies currently manage CCR at onsite storage units consisting of landfills and surface impoundments (CCR Units) at 22 electric generating plants. In addition to on-site storage, the traditional 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 service territory each have their own regulatory requirements. Each traditional operating company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate 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 mandate 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 mandated closure of a CCR Unit. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the traditional operating companies' ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain; however, Southern Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $860 million and ongoing post-closure care of approximately $140 million. Certain of the traditional operating companies have previously recorded asset retirement obligations (ARO) associated with ash ponds of $506 million, or $468 million on a nominal dollar basis, based on existing state requirements. During 2015, the traditional operating companies will record AROs for any incremental estimated closure costs resulting from acceleration in the timing of any currently planned closures and for differences between existing state requirements and the requirements of the CCR Rule. Southern Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

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 properties. The traditional operating companies 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 operating companies have each received authority from their respective state PSCs to recover approved environmental compliance costs through regulatory mechanisms. These rates are adjusted annually or as necessary within limits approved by the state PSCs. The traditional operating companies 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 2014, the EPA published three sets of proposed standards that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. On January 8, 2014, the EPA published proposed standards for new units, and, on June 18, 2014, the EPA published proposed standards governing existing units, known as the Clean Power Plan, and separate standards governing CO_2 emissions from modified and reconstructed units. The EPA's proposed Clean Power Plan establishes guidelines for states to develop plans to address CO_2 emissions from existing fossil fuel-fired electric generating units. The EPA's proposed guidelines establish state-specific interim and final CO_2 emission rate goals to be achieved between 2020 and 2029 and 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. 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 market-based contracts.

The Southern Company system filed comments on the EPA's proposed Clean Power Plan on December 1, 2014. These comments addressed legal and technical issues in addition to providing a preliminary estimated cost of complying with the proposed guidelines utilizing one of the EPA's compliance scenarios. Costs associated with this proposal could be significant to the utility industry and the Southern Company system. However, the ultimate financial and operational impact of the proposed Clean Power Plan on the Southern Company system cannot be determined at this time and will depend upon numerous known and unknown factors. Some of the unknown factors include: the structure, timing, and content of the EPA's final guidelines; individual state implementation of these guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

Over the past several years, the U.S. Congress has also considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Southern Company system's 2013 greenhouse gas emissions were approximately 102 million metric tons of CO_2 equivalent. The preliminary estimate of the Southern Company system's 2014 greenhouse gas emissions on the same basis is approximately 112 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.

Retail 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 "Retail Regulatory Matters – Alabama Power" for additional information regarding Alabama Power's rate mechanisms and accounting orders.

Rate RSE

Alabama Power's Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate 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 weighted cost of equity (WCE) range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.

On December 1, 2014, Alabama Power submitted the required annual filing under Rate RSE to the Alabama PSC. The Rate RSE increase was 3.49%, or $181 million annually, effective January 1, 2015. The revenue adjustment includes the performance based adder of 0.07%. Under the terms of Rate RSE, the maximum increase for 2016 cannot exceed 4.51%.

Rate CNP

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 4, 2014, 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, 2014 through March 31, 2015. It is anticipated that no adjustment will be made to Rate CNP PPA in 2015.

Alabama Power has elected the normal purchase normal sale (NPNS) scope exception under the derivative accounting rules for its two wind PPAs, which total approximately 400 MWs. The NPNS exception allows the PPAs to be recorded at a cost, rather than fair value, basis. The industry's application of the NPNS exception to certain physical forward transactions in nodal markets was previously under review by the SEC at the request of the electric utility industry. In June 2014, the SEC requested the Financial Accounting Standards Board to address the issue through the Emerging Issues Task Force (EITF). Any accounting decisions will now be subject to EITF deliberations. The outcome of the EITF's deliberations cannot be determined at this time. If

Alabama Power is ultimately required to record these PPAs at fair value, an offsetting regulatory asset or regulatory liability will be recorded.

Rate CNP Environmental allows for the recovery of Alabama Power's retail costs associated with environmental laws, regulations, or other such mandates. Rate CNP Environmental is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. The Rate CNP Environmental increase effective January 1, 2015 is 1.5%, or $75 million annually, based upon projected billings.

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 would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement. See "Environmental Matters – Environmental Statutes and Regulations" herein for additional information regarding environmental regulations.

As part of its environmental compliance strategy, Alabama Power plans to retire Plant Gorgas Units 6 and 7. These units represent 200 MWs of Alabama Power's approximately 12,200 MWs of generating capacity. Alabama Power also plans to cease 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. Additionally, Alabama Power expects to cease using coal at Plant Barry Unit 3 (225 MWs) and Plant Greene County Units 1 and 2 (300 MWs) and begin operating those units solely on natural gas. These plans are expected to be effective no later than April 2016.

In accordance with an accounting order from the Alabama PSC, Alabama Power will transfer the unrecovered plant asset balances to a regulatory asset at their respective retirement dates. The regulatory asset will be amortized through Rate CNP Environmental over the remaining useful lives, as established prior to the decision for retirement. As a result, these decisions will not have a significant impact on Southern Company's financial statements.

Cost of Removal Accounting Order

In accordance with an accounting order issued on November 3, 2014 by the Alabama PSC, at December 31, 2014, Alabama Power 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 account balances amortized 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 August 2013, respectively. Approximately $95 million of non-nuclear outage costs and $28 million of compliance and pension costs were fully amortized at December 31, 2014.

The cost of removal accounting order also required Alabama Power to terminate, as of December 31, 2014, the regulatory asset accounts created pursuant to the compliance and pension cost accounting order and the non-nuclear outage accounting order. Consequently, Alabama Power will not defer any expenditures in 2015, 2016, and 2017 related to critical electric infrastructure and domestic nuclear facilities, as allowed under the previous orders.

Non-Environmental Federal Mandated Costs Accounting Order

On December 9, 2014, pending the development of a new cost recovery mechanism, the Alabama PSC issued an accounting order authorizing the deferral as a regulatory asset of up to $50 million of costs associated with non-environmental federal mandates that would otherwise impact rates in 2015.

On February 17, 2015, Alabama Power filed a proposed modification to Rate CNP Environmental with the Alabama PSC to include compliance costs for both environmental and non-environmental mandates. The non-environmental costs that would be recovered through the revised mechanism concern laws, regulations, and other mandates directed at the utility industry involving the security, reliability, safety, sustainability, or similar considerations impacting Alabama Power's facilities or operations. If approved as requested, the effective date for the revised mechanism would be March 20, 2015, upon which the regulatory asset balance would be reclassified to the under recovered balance for Rate CNP Environmental, and the related customer rates would not become effective before January 2016. The ultimate outcome of this matter cannot be determined at this time.

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 "Retail Regulatory Matters – Georgia Power" for additional information.

Rate Plans

In December 2013, the Georgia PSC voted to approve the 2013 ARP. The 2013 ARP reflects the settlement agreement among Georgia Power, the Georgia PSC's Public Interest Advocacy Staff, and 11 of the 13 intervenors, which was filed with the Georgia PSC in November 2013.

On January 1, 2014, in accordance with the 2013 ARP, Georgia Power increased its tariffs as follows: (1) traditional base tariff rates by approximately $80 million; (2) ECCR tariff by approximately $25 million; (3) DSM tariffs by approximately $1 million; and (4) MFF tariff by approximately $4 million, for a total increase in base revenues of approximately $110 million.

On February 19, 2015, in accordance with the 2013 ARP, the Georgia PSC approved adjustments to traditional base, ECCR, DSM, and MFF tariffs effective January 1, 2015 as follows:

- Traditional base tariffs by approximately $107 million to cover additional capacity costs;
- ECCR tariff by approximately $23 million;
- DSM tariffs by approximately $3 million; and
- MFF tariff by approximately $3 million to reflect the adjustments above.

The sum of these adjustments resulted in a base revenue increase of approximately $136 million in 2015.

The 2016 base rate increase, which was approved in the 2013 ARP, will be determined through a compliance filing expected to be filed in late 2015, and will be subject to review by the Georgia PSC.

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. However, if at any time during the term of the 2013 ARP, Georgia Power projects that its retail earnings will be below 10.00% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff that would be used to adjust Georgia Power's earnings back to a 10.00% retail ROE. The Georgia PSC would have 90 days to rule on Georgia Power's request. The ICR tariff will expire at the earlier of January 1, 2017 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, Georgia Power may file a full rate case. In 2014, Georgia Power's retail ROE exceeded 12.00%, and Georgia Power expects to refund to retail customers approximately $13 million in 2015, subject to review and approval by the Georgia PSC.

Except as provided above, Georgia Power will not file for a general base rate increase while the 2013 ARP is in effect. Georgia Power is required to file a general rate case by July 1, 2016, in response to which the Georgia PSC would be expected to determine whether the 2013 ARP should be continued, modified, or discontinued.

Integrated Resource Plans

See "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," "– Coal Combustion Residuals," and "– Global Climate Issues," and "Rate Plans" 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; the State of Georgia's Multi-Pollutant Rule; 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.

In July 2013, the Georgia PSC approved Georgia Power's latest triennial Integrated Resource Plan (2013 IRP) including Georgia Power's request to decertify 16 coal- and oil-fired units totaling 2,093 MWs. Several factors, including the cost to comply with existing and future environmental regulations, recent and forecasted economic conditions, and lower natural gas prices, contributed to the decision to close these units.

Plant Branch Units 3 and 4 (1,016 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) will be decertified and retired by April 16, 2015, the compliance date of the MATS rule. The decertification date of Plant Branch Unit 1 (250 MWs) was extended from December 31, 2013 as specified in the final order in the 2011 Integrated Resource Plan Update (2011 IRP Update) to coincide with the decertification date of Plant Branch Units 3 and 4. The decertification and retirement of Plant Kraft Units 1 through 4 (316 MWs) were also approved and will be effective by April 16, 2016, based on a

one-year extension of the MATS rule compliance date that was approved by the State of Georgia Environmental Protection Division in September 2013 to allow for necessary transmission system reliability improvements. In July 2013, the Georgia PSC approved the switch to natural gas as the primary fuel for Plant Yates Units 6 and 7. In September 2013, Plant Branch Unit 2 (319 MWs) was retired as approved by the Georgia PSC in the 2011 IRP Update in order to comply with the State of Georgia's Multi-Pollutant Rule.

In the 2013 ARP, the Georgia PSC approved the amortization of the CWIP balances related to environmental projects that will not be completed at Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 over nine years beginning in January 2014 and the amortization of any remaining net book values of Plant Branch Unit 2 from October 2013 to December 2022, Plant Branch Unit 1 from May 2015 to December 2020, Plant Branch Unit 3 from May 2015 to December 2023, and Plant Branch Unit 4 from May 2015 to December 2024. The Georgia PSC deferred a decision regarding the appropriate recovery period for the costs associated with unusable materials and supplies remaining at the retiring plants to Georgia Power's next base rate case, which Georgia Power expects to file in 2016 (2016 Rate Case). In the 2013 IRP, the Georgia PSC also deferred decisions regarding the recovery of any fuel related costs that could be incurred in connection with the retirement units to be addressed in future fuel cases.

On July 1, 2014, the Georgia PSC approved Georgia Power's request to cancel the proposed biomass fuel conversion of Plant Mitchell Unit 3 (155 MWs) because it would not be cost effective for customers. Georgia Power expects to request decertification of Plant Mitchell Unit 3 in connection with the triennial Integrated Resource Plan to be filed in 2016. Georgia Power plans to continue to operate the unit as needed until the MATS rule becomes effective in April 2015.

The decertification of these units and fuel conversions are not expected to have a material impact on Southern Company's financial statements; however, the ultimate outcome depends on the Georgia PSC's order in the 2016 Rate Case and future fuel cases and cannot be determined at this time.

Retail Fuel Cost Recovery

The traditional 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 operating companies continuously monitor their under or over recovered fuel cost balances. On January 20, 2015, the Georgia PSC approved the deferral of Georgia Power's next fuel case filing until at least June 30, 2015.

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

Construction Program

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 generating facilities, as well as adding or changing fuel sources for certain existing units, adding environmental control equipment, and expanding the transmission and distribution systems. For the traditional 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. The construction programs of the traditional operating companies and Southern Power are currently estimated to include an investment of approximately $6.7 billion, $5.4 billion, and $4.3 billion for 2015, 2016, and 2017, respectively.

The two largest construction projects currently underway in the Southern Company system are Plant Vogtle Units 3 and 4 and the Kemper IGCC. Georgia Power has a 45.7% ownership interest in Plant Vogtle Units 3 and 4, each with approximately 1,100 MWs, and Mississippi Power is ultimately expected to hold an 85% ownership interest in the 582-MW Kemper IGCC. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" for additional information.

From 2013 through December 31, 2014, the Company recorded pre-tax charges totaling $2.05 billion ($1.26 billion after-tax) for revisions of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC above the $2.88 billion cost cap established by the Mississippi PSC, net of the DOE Grants and excluding the Cost Cap Exceptions. In subsequent periods, any further changes in the estimated costs to complete construction of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the Company's statements of income and these changes could be material.

On January 29, 2015, Georgia Power announced that it was notified by the consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc., a subsidiary of The Shaw Group Inc., which was acquired by Chicago Bridge & Iron Company N.V. (collectively, Contractor) of the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4, which would incrementally delay the previously disclosed estimated in-service dates by 18 months (from the fourth quarter of 2017 to the second quarter of 2019 for Unit 3 and from the fourth quarter of 2018 to the second quarter of 2020 for Unit 4).

While Georgia Power has not agreed to any change to the guaranteed substantial completion dates (April 2016 for Unit 3 and April 2017 for Unit 4) included in the engineering, procurement, and construction agreement relating to Plant Vogtle Units 3 and 4, Georgia Power's twelfth Vogtle Construction Monitoring (VCM) report, filed February 27, 2015, includes a requested amendment to the Plant Vogtle Units 3 and 4 certificate to reflect the Contractor's revised forecast, to include the estimated owner's costs associated with the proposed 18-month Contractor delay, and to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 from $4.4 billion to $5.0 billion. No Contractor costs related to the Contractor's proposed 18-month delay are included in the twelfth VCM report. The twelfth VCM report estimates total associated financing costs during the construction period to be approximately $2.5 billion.

Additionally, there are certain risks associated with the construction program in general and certain risks associated with the licensing, construction, and operation of nuclear generating units in particular, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. The ultimate outcome of these events cannot be determined at this time.

See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" 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. The ultimate outcome of these tax matters cannot be determined at this time.

Bonus Depreciation

On December 19, 2014, the Tax Increase Prevention Act of 2014 (TIPA) was signed into law. The TIPA retroactively extended several tax credits through 2014 and extended 50% bonus depreciation for property placed in service in 2014 (and for certain long-term production-period projects to be placed in service in 2015). The extension of 50% bonus depreciation will have a positive impact on Southern Company's cash flows and, combined with bonus depreciation allowed under the American Taxpayer Relief Act of 2012 (ATRA), will result in approximately $630 million of positive cash flows. Additionally, the estimated cash flow benefit impact of bonus depreciation for long-term production-period projects to be placed in service in 2015 related to TIPA is expected to be approximately $220 million to $240 million for the 2015 tax year.

Tax Credits

The IRS allocated $279 million (Phase II) of Internal Revenue Code of 1986, as amended (Internal Revenue Code) Section 48A tax credits to Mississippi Power in connection with the Kemper IGCC. Through December 31, 2014, Southern Company had recorded tax benefits totaling $276 million for the Phase II credits, of which approximately $210 million had been utilized through that date. These credits will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC and are dependent upon meeting the IRS certification requirements, including an in-service date no later than April 19, 2016 and 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. Mississippi Power currently expects to place the Kemper IGCC in service in the first half of 2016. In addition, a portion of the Phase II tax credits will be subject to recapture upon completion of SMEPA's proposed purchase of an undivided interest in the Kemper IGCC.

In 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA). Major tax incentives in the ARRA included renewable energy incentives. In January 2013, the ATRA was signed into law. The ATRA retroactively extended several renewable energy incentives through 2013, including extending federal ITCs for biomass projects which began construction before January 1, 2014. The current law provides for a 30% federal ITC for solar facilities placed in service through 2016 and, unless extended, will adjust to 10% for solar facilities placed in service thereafter. The Company has received ITCs in connection with Southern Power's investments in solar and biomass facilities. See Note 1 to the financial statements under "Income and Other Taxes" for additional information regarding credits amortized and the tax benefit related to basis differences in 2014, 2013, and 2012.

Additionally, the TIPA extended the production tax credit for wind and certain other renewable sources of electricity to facilities for which construction had commenced by the end of 2014.

Section 174 Research and Experimental Deduction

Southern Company reduced tax payments for 2014 and included in its 2013 consolidated federal income tax return deductions for research and experimental expenditures related to the Kemper IGCC. Due to the uncertainty related to this tax position, Southern Company recorded an unrecognized tax benefit of approximately $160 million as of December 31, 2014. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

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.

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.

Electric Utility Regulation

Southern Company's traditional operating companies, which comprised approximately 94% of Southern Company's total operating revenues for 2014, are subject to retail regulation by their respective state PSCs and wholesale regulation by the FERC. These regulatory agencies set the rates the traditional operating companies are permitted to charge customers based on allowable costs, including a reasonable return on equity. As a result, the traditional operating companies 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 operating companies; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

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

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, in accordance with GAAP, 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 financial position, results of operations, or cash flows.

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 in accordance with GAAP 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 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. Southern Company discounts the future cash flows related to its postretirement benefit plans 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 purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $636 million and $92 million, respectively. The adoption of new mortality tables will increase net periodic costs related to the Company's pension plans and other postretirement benefit plans in 2015 by $86 million and $10 million, respectively.

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 2015	Increase/ (Decrease) in Projected Obligation for Pension Plan at December 31, 2014	Increase/(Decrease) in Projected Obligation for Other Postretirement Benefit Plans at December 31, 2014
		(in millions)	
25 basis point change in discount rate	$36/$(34)	$409/$(385)	$64/$(61)
25 basis point change in salaries	$19/$(18)	$103/$(99)	$–/$–
25 basis point change in long-term return on plan assets	$24/$(24)	N/A	N/A

N/A – Not applicable

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

During 2014, Mississippi Power further extended the scheduled in-service date for the Kemper IGCC to the first half of 2016 and 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 DOE Grants and excluding the Cost Cap Exceptions. Mississippi Power does not intend to seek any rate recovery or any joint owner contributions for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions.

As a result of the revisions to the cost estimate, Southern Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC of $70.0 million ($43.2 million after tax) in the fourth quarter 2014, $418.0 million ($258.1 million after tax) in the third quarter 2014, $380.0 million ($234.7 million after tax) in the first quarter 2014, $40.0 million ($24.7 million after tax) in the fourth quarter 2013, $150.0 million ($92.6 million after tax) in the third quarter 2013, $450.0 million ($277.9 million after tax) in the second quarter 2013, and $540.0 million ($333.5 million after tax) in the first quarter 2013. In the aggregate, Southern Company has incurred charges of $2.05 billion ($1.26 billion after tax) as a result of changes in the cost estimate for the Kemper IGCC through December 31, 2014.

Mississippi Power has experienced, and may continue to experience, material changes in the cost estimate for the Kemper IGCC. In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the 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 further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (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).

Mississippi Power's revised cost estimate includes costs through March 31, 2016. Any further extension of the in-service date is currently estimated to result in additional base costs of approximately $25 million to $30 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. Any further extension of the in-service date with respect to the Kemper IGCC 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 $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting fees and legal fees which are being deferred as regulatory assets and are estimated to total approximately $7 million per month.

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.

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. Southern Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Earnings in 2014 and 2013 were negatively affected by revisions to the cost estimate for the Kemper IGCC; however, Southern Company's financial condition remained stable at December 31, 2014 and December 31, 2013. Through December 31, 2014, Southern Company has incurred non-recoverable cash expenditures of $1.3 billion and is expected to incur approximately $702 million in additional non-recoverable cash expenditures through completion of the Kemper IGCC. Southern Company'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, to comply with environmental regulations, 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 2015 through 2017, Southern Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Southern Company system's projected capital expenditures in that period include investments to build new generation facilities, to maintain existing generation facilities, to add environmental equipment for existing generating units, to add or change fuel sources for certain existing units, and to expand and improve transmission and distribution facilities. 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 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.

Southern Company's investments in the qualified pension plan and the nuclear decommissioning trust funds increased in value as of December 31, 2014 as compared to December 31, 2013. In December 2014, certain of the traditional operating companies and other subsidiaries voluntarily contributed an aggregate of $500 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. 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 2014 totaled $5.8 billion, a decrease of $282 million from 2013. Significant changes in operating cash flow for 2014 as compared to 2013 include $500 million of voluntary contributions to the qualified pension plan and an increase in receivables due to under recovered fuel costs, partially offset by an increase in accrued compensation. Net cash provided from operating activities in 2013 totaled $6.1 billion, an increase of $1.2 billion from 2012. The most significant change in operating cash flow for 2013 as compared to 2012 was a decrease in fossil fuel stock due to an increase in KWH generation.

Net cash used for investing activities in 2014, 2013, and 2012 totaled $6.4 billion, $5.7 billion, and $5.2 billion, respectively. The cash used for investing activities in each of these years was primarily due to gross property additions for installation of equipment to comply with environmental standards, construction of generation, transmission, and distribution facilities, acquisitions of solar facilities, and purchases of nuclear fuel.

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. Net cash used for financing activities totaled $324 million in 2013 due to redemptions of long-term debt and payments of common stock dividends, partially offset by issuances of long-term debt and common stock and an increase in 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 2014 included an increase of $3.7 billion in total property, plant, and equipment for the installation of equipment to comply with environmental standards and construction of generation, transmission, and distribution facilities and a $1.8 billion increase in other regulatory assets, deferred related to pension and other postretirement benefits. Other significant changes included a $2.9 billion increase in short-term debt primarily related to debt maturing within the next year and borrowings to fund the Southern Company subsidiaries' continuous construction programs, a $1.2 billion increase in stockholders' equity, a $1.0 billion increase in accumulated deferred income taxes primarily as a result of bonus depreciation, and a $971 million increase in employee benefit obligations primarily as a result of changes in actuarial assumptions. See Note 2 and Note 5 to the financial statements for additional information regarding retirement benefits and deferred income taxes, respectively.

At the end of 2014, the market price of Southern Company's common stock was $49.11 per share (based on the closing price as reported on the New York Stock Exchange) and the book value was $21.98 per share, representing a market-to-book value ratio of 223%, compared to $41.11, $21.43, and 192%, respectively, at the end of 2013.

Sources of Capital

Southern Company intends to meet its future capital needs through operating cash flow, 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 to be raised in 2015, as well as in subsequent years, will be contingent on Southern Company's investment opportunities and the Southern Company system's capital requirements.

Except as described herein, the traditional operating companies and Southern Power 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.

On February 20, 2014, Georgia Power and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement), pursuant to which the DOE agreed to guarantee borrowings to be made by Georgia Power under a multi-advance credit facility (FFB Credit Facility) among Georgia Power, the DOE, and the FFB. 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 also are secured by a first priority lien on (i) Georgia Power's 45.7% 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. Under the FFB Credit Facility, Georgia Power may make term loan borrowings through the FFB. Proceeds of borrowings made under the FFB Credit

Facility will 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). 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. 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 – Georgia Power – Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

Eligible Project Costs incurred through December 31, 2014 would allow for borrowings of up to $2.1 billion under the FFB Credit Facility. Through December 31, 2014, Georgia Power had borrowed $1.2 billion under the FFB Credit Facility, leaving $0.9 billion of currently available borrowing ability.

Mississippi Power received $245 million of DOE Grants in prior years that were used for the construction of the Kemper IGCC. An additional $25 million of DOE Grants is expected to be received for the commercial operation of the Kemper IGCC. 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 operating companies is generally subject to the approval of the applicable state PSC. The issuance of all securities by Mississippi Power and Southern 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 operating company, and Southern Power obtain 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 each company are not commingled with funds of any other company in the Southern Company system.

As of December 31, 2014, Southern Company's current liabilities exceeded current assets by $2.6 billion, primarily due to long-term debt of the traditional operating companies and Southern Power that is due within one year of $3.3 billion. To meet short-term cash needs and contingencies, Southern Company has substantial cash flow from operating activities and access to capital markets and financial institutions.

At December 31, 2014, Southern Company and its subsidiaries had approximately $710 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2014 were as follows:

	Expires						Executable Term Loans		Due Within One Year	
Company	2015	2016	2017	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
					(in millions)		(in millions)		(in millions)	
Southern Company	$ —	$ —	$ —	$1,000	$1,000	$ 1,000	$ —	$ —	$ —	$ —
Alabama Power	228	50	—	1,030	1,308	1,308	58	—	58	170
Georgia Power	—	150	—	1,600	1,750	1,736	—	—	—	—
Gulf Power	80	165	30	—	275	275	50	—	50	30
Mississippi Power	135	165	—	—	300	300	25	40	65	70
Southern Power	—	—	—	500	500	488	—	—	—	—
Other	70	—	—	—	70	70	20	—	20	50
Total	$ 513	$ 530	$ 30	$4,130	$5,203	$ 5,177	$ 153	$ 40	$ 193	$ 320

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 traditional operating companies' variable rate pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014 was approximately $1.8 billion. In addition, at December 31, 2014, the traditional operating companies had $476 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months. As of December 31, 2014, $98 million of certain

pollution control revenue bonds of Georgia Power were reclassified to securities due within one year in anticipation of their redemption in connection with unit retirement decisions.

Subject to applicable market conditions, Southern Company and its subsidiaries expect to renew their bank credit arrangements as needed, prior to expiration.

Most of these bank credit arrangements contain covenants that limit debt levels and contain 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. Southern Company, the traditional operating companies, and Southern Power are currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

Southern Company, the traditional operating companies, and Southern Power make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. Southern Company, the traditional operating companies, and Southern Power may also borrow through various other arrangements with banks. 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		Short-term Debt During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
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%**	
December 31, 2013:					
Commercial paper	$ 1,082	0.2%	$ 993	0.3%	$ 1,616
Short-term bank debt	400	0.9%	107	0.9%	400
Total	$ 1,482	0.4%	$ 1,100	0.3%	
December 31, 2012:					
Commercial paper	$ 820	0.3%	$ 550	0.3%	$ 938
Short-term bank debt	—	—%	116	1.2%	300
Total	$ 820	0.3%	$ 666	0.5%	

(a) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2014, 2013, and 2012.

The Company believes the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, bank notes, and cash from operations.

Financing Activities

During 2014, Southern Company issued approximately 20.8 million shares of common stock (including approximately 5.0 million treasury shares) for approximately $806 million through the employee and director stock plans and the Southern Investment Plan. The Company may satisfy its obligations with respect to the plans in several ways, including through using newly issued shares or treasury shares or acquiring shares on the open market through the independent plan administrators.

From August 2013 through December 2014, Southern Company used shares held in treasury, to the extent available, and newly issued shares to satisfy the requirements under the Southern Investment Plan and the employee savings plan. Beginning in January 2015, Southern Company ceased issuing additional shares under the Southern Investment Plan and the employee savings plan. All sales under these plans are now being funded with shares acquired on the open market by the independent plan administrators.

Beginning in 2015, Southern Company expects to repurchase shares of common stock to offset all or a portion of the incremental shares issued under its employee and director stock plans, including through stock option exercises. The Southern Company Board of Directors has approved the repurchase of up to 20 million shares of common stock for such purpose until December 31, 2017. Repurchases may be made by means of open market purchases, privately negotiated transactions, or accelerated or other share repurchase programs, in accordance with applicable securities laws.

The following table outlines the long-term debt financing activities for Southern Company and its subsidiaries for the year ended December 31, 2014:

Company	Senior Note Issuances	Senior Note Maturities	Revenue Bond Issuances and Remarketings of Purchased Bonds[a]	Revenue Bond Redemptions	Other Long-Term Debt Issuances	Other Long-Term Debt Redemptions[b] and Maturities
			(in millions)			
Southern Company	$ 750	$ 350	$ —	$ —	$ —	$ —
Alabama Power	400	—	254	254	—	—
Georgia Power	—	—	40	37	1,200	5
Gulf Power	200	75	42	29	—	—
Mississippi Power	—	—	—	—	493	256
Southern Power	—	—	—	—	10	10
Other	—	—	—	—	—	19
Elimination[c]	—	—	—	—	(220)	(220)
Total	$ 1,350	$ 425	$ 336	$ 320	$ 1,483	$ 70

(a) Includes remarketing by Gulf Power of $13 million aggregate principal amount of revenue bonds previously purchased and held by Gulf Power since December 2013 and remarketing by Georgia Power of $40 million aggregate principal amount of revenue bonds previously purchased and held by Georgia Power since 2010.

(b) Includes reductions in capital lease obligations resulting from cash payments under capital leases.

(c) Intercompany loan from Southern Company to Mississippi Power eliminated in Southern Company's Consolidated Financial Statements. This loan was repaid on September 29, 2014.

In May 2014, Southern Company's $350 million aggregate principal amount of its Series 2009A 4.15% Senior Notes due May 15, 2014 matured.

In August 2014, Southern Company issued $400 million aggregate principal amount of Series 2014A 1.30% Senior Notes due August 15, 2017 and $350 million aggregate principal amount of Series 2014B 2.15% Senior Notes due September 1, 2019. The proceeds were used to pay a portion of Southern Company's outstanding short-term indebtedness and for other general corporate purposes.

Southern Company's subsidiaries used the proceeds of the debt issuances shown in the table above for the redemptions and maturities shown in the table above, to repay short-term indebtedness, and for general corporate purposes, including their respective continuous construction programs.

In addition to the amounts reflected in the table above, in June 2014, Southern Company entered into a 90-day floating rate bank loan bearing interest based on one-month LIBOR. This short-term loan was for $250 million aggregate principal amount and the proceeds were used for working capital and other general corporate purposes, including the investment by Southern Company in its subsidiaries. This bank loan was repaid in August 2014.

In addition to the amounts reflected in the table above, in January 2014 and October 2014, Mississippi Power received an additional $75 million and $50 million, respectively, of interest-bearing refundable deposits from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle – Proposed Sale of Undivided Interest to SMEPA" for additional information.

Georgia Power's "Other Long-Term Debt Issuances" reflected in the table above include borrowings under the FFB Credit Facility in an aggregate principal amount of $1.0 billion on February 20, 2014 and $200 million on December 11, 2014. The interest rate applicable to $500 million of the initial advance under the FFB Credit Facility is 3.860% for an interest period that extends to 2044 and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to 2029 and is expected to be reset from time to time thereafter through 2044. The interest rate applicable to the $200 million advance in

December 2014 is 3.002% for an interest period that extends to 2044. The final maturity date for all advances under the FFB Credit Facility is February 20, 2044. The proceeds of the borrowings in 2014 under the FFB Credit Facility were used to reimburse Georgia Power for Eligible Project Costs relating to the construction of Plant Vogtle Units 3 and 4. 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.

Under the Loan Guarantee Agreement, Georgia Power 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 Georgia Power or Southern Nuclear to comply with requirements of law or DOE loan guarantee program requirements. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information.

In February 2014, Georgia Power repaid three four-month floating rate bank loans in an aggregate principal amount of $400 million.

During 2014, Alabama Power entered into forward-starting interest rate swaps to hedge exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $200 million.

In October 2014, Georgia Power entered into interest rate swaps to hedge exposure to interest rate changes related to existing debt. The notional amount of the swaps totaled $900 million.

In November and December 2014, Georgia Power entered into forward-starting interest rate swaps to hedge exposure to interest rate changes related to anticipated borrowings under the FFB Credit Facility in 2015. The notional amount of the swaps totaled $700 million.

Subsequent to December 31, 2014, Alabama Power announced the redemption of $250 million aggregate principal amount of its Series DD 5.65% Senior Notes due March 15, 2035, which will occur on March 16, 2015.

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

Southern Company and its subsidiaries do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change of certain subsidiaries to BBB and Baa2, or 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, interest rate derivatives, and construction of new generation at Plant Vogtle Units 3 and 4.

The maximum potential collateral requirements under these contracts at December 31, 2014 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and Baa2	$ 9
At BBB- and/or Baa3	435
Below BBB- and/or Baa3	2,305

Subsequent to December 31, 2014, Moody's affirmed the senior unsecured debt rating of Mississippi Power and revised the ratings outlook for Mississippi Power from stable to negative.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the ability of Southern Company and its subsidiaries to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

Market Price Risk

The Southern Company system is exposed to market risks, primarily commodity price risk and interest rate risk. The Southern Company system may also occasionally have limited exposure to foreign currency exchange rates. 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 outstanding at December 31, 2014 have a notional amount of $2.1 billion and are related to fixed and floating rate obligations. The weighted average interest rate on $3.4 billion of long-term variable interest rate exposure at January 1, 2015 was 0.94%. 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 $34 million at January 1, 2015. 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 operating companies continue to have limited exposure to market volatility in interest rates, foreign currency, 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 operating companies 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. The traditional operating companies continue to manage fuel-hedging programs implemented per the guidelines of their respective state PSCs. Southern Company had no material change in market risk exposure for the year ended December 31, 2014 when compared to the year ended December 31, 2013.

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:

	2014 Changes	2013 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (32)**	$ (85)
Contracts realized or settled:		
Swaps realized or settled	**(9)**	43
Options realized or settled	**6**	19
Current period changes[(a)]:		
Swaps	**(131)**	2
Options	**(22)**	(11)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (188)**	$ (32)

(a) 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:

	2014	2013
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	**200**	216
Commodity – Natural gas options	**44**	59
Total hedge volume	**244**	275

The weighted average swap contract cost above market prices was approximately $0.84 per mmBtu as of December 31, 2014 and $0.10 per mmBtu as of December 31, 2013. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. The majority of the natural gas hedge gains and losses are recovered through the traditional operating companies' fuel cost recovery clauses.

At December 31, 2014 and 2013, 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.

Southern Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 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, 2014 were as follows:

	Fair Value Measurements December 31, 2014			
	Total Fair Value	Maturity		
		Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ —	$ —	$ —	$ —
Level 2	(188)	(109)	(76)	(3)
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ (188)	$ (109)	$ (76)	$ (3)

Southern Company is exposed to market price risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. 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. Therefore, Southern 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.

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 be $6.7 billion for 2015, $5.4 billion for 2016, and $4.3 billion for 2017, which includes expenditures related to the construction and start-up of the Kemper IGCC of $801 million for 2015 and $132 million for 2016. The amounts related to the construction and start-up of the Kemper IGCC exclude

SMEPA's proposed acquisition of a 15% ownership share of the Kemper IGCC for approximately $596 million (including construction costs for all prior periods relating to its proposed ownership interest). Capital expenditures to comply with environmental statutes and regulations included in these estimated amounts are $1.0 billion, $0.5 billion, and $0.6 billion for 2015, 2016, and 2017, respectively. The Southern Company system's amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" for additional information.

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" 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 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; 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. Additionally, planned expenditures for plant acquisitions may vary due to market opportunities and Southern Power's ability to execute its growth strategy. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" for information regarding additional factors that may impact construction expenditures.

In addition, the construction program includes the development and construction of new 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. 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, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction 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).

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 substantially all employees and funds trusts to the extent required by the traditional operating companies' respective regulatory commissions.

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, and other purchase commitments 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

	2015	2016-2017	2018-2019	After 2019	Total
			(in millions)		
Long-term debt[a] —					
Principal	$ 3,302	$ 3,345	$ 2,050	$ 15,282	$ 23,979
Interest	857	1,563	1,355	11,379	15,154
Preferred and preference stock dividends[b]	68	136	136	—	340
Financial derivative obligations[c]	138	76	3	—	217
Operating leases[d]	100	154	73	248	575
Capital leases[d]	31	25	22	81	159
Unrecognized tax benefits[e]	170	—	—	—	170
Purchase commitments —					
Capital[f]	6,222	8,899	—	—	15,121
Fuel[g]	4,012	5,155	3,321	9,869	22,357
Purchased power[h]	327	738	761	3,892	5,718
Other[i]	233	476	378	1,369	2,456
Trusts —					
Nuclear decommissioning[j]	5	11	11	110	137
Pension and other postretirement benefit plans[k]	112	224	—	—	336
Total	$ 15,577	$ 20,802	$ 8,110	$ 42,230	$ 86,719

(a) All amounts are reflected based on final maturity dates. 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, 2015, 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) 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) The Southern Company system provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with environmental regulations. Estimates related to the construction and start-up of the Kemper IGCC exclude SMEPA's proposed acquisition of a 15% ownership share of the Kemper IGCC. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information. These amounts exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements which are reflected separately. At December 31, 2014, 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.

(g) 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, 2014.

(h) Estimated minimum long-term obligations for various PPA purchases from gas-fired, biomass, and wind-powered facilities. A total of $1.1 billion of biomass PPAs is contingent upon the counterparties meeting specified contract dates for commercial operation and may change as a result of regulatory action. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Georgia Power – Renewables Development" for additional information.

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

(j) 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.

(k) 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 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 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 2014 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, the strategic goals for the wholesale business, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, completion dates of acquisitions and construction projects, filings with state and federal regulatory authorities, impact of the TIPA, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, CCR, and emissions of sulfur, nitrogen, CO_2, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, and IRS and state tax audits;
- 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, 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, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction 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 operational and environmental performance standards, including any PSC requirements 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 Southern Company's employee and retiree benefit plans and the Southern Company system's 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;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions and related legal proceedings involving the commercial parties;
- actions related to cost recovery for the Kemper IGCC, including actions relating to proposed securitization, Mississippi PSC approval of a rate recovery plan, including the ability to complete the proposed sale of an interest in the Kemper IGCC to SMEPA, the ability to utilize bonus depreciation, which currently requires that assets be placed in service in 2015, and satisfaction of requirements to utilize ITCs and grants;
- Mississippi PSC review of the prudence of Kemper IGCC costs;

- the ultimate outcome and impact of the February 2015 decision of the Mississippi Supreme Court and any further legal or regulatory proceedings regarding any settlement agreement between Mississippi Power and the Mississippi PSC, the March 2013 rate order regarding retail rate increases, or the Baseload Act;
- the ability to successfully operate the electric utilities' generating, transmission, and distribution 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, or financial risks;
- 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 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 or 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 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 subsidiaries to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Southern Company system'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 Southern Company from time to time with the SEC.

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

[This page intentionally left blank]

CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2014, 2013, and 2012
Southern Company and Subsidiary Companies 2014 Annual Report

	2014	2013	2012
		(in millions)	
Operating Revenues:			
Retail revenues	$ 15,550	$ 14,541	$ 14,187
Wholesale revenues	2,184	1,855	1,675
Other electric revenues	672	639	616
Other revenues	61	52	59
Total operating revenues	18,467	17,087	16,537
Operating Expenses:			
Fuel	6,005	5,510	5,057
Purchased power	672	461	544
Other operations and maintenance	4,354	3,846	3,772
Depreciation and amortization	1,945	1,901	1,787
Taxes other than income taxes	981	934	914
Estimated loss on Kemper IGCC	868	1,180	—
Total operating expenses	14,825	13,832	12,074
Operating Income	3,642	3,255	4,463
Other Income and (Expense):			
Allowance for equity funds used during construction	245	190	143
Interest income	19	19	40
Interest expense, net of amounts capitalized	(835)	(824)	(859)
Other income (expense), net	(63)	(81)	(38)
Total other income and (expense)	(634)	(696)	(714)
Earnings Before Income Taxes	3,008	2,559	3,749
Income taxes	977	849	1,334
Consolidated Net Income	2,031	1,710	2,415
Dividends on Preferred and Preference Stock of Subsidiaries	68	66	65
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	$ 1,963	$ 1,644	$ 2,350
Common Stock Data:			
Earnings per share (EPS) —			
Basic EPS	$ 2.19	$ 1.88	$ 2.70
Diluted EPS	2.18	1.87	2.67
Average number of shares of common stock outstanding — (in millions)			
Basic	897	877	871
Diluted	901	881	879

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2014, 2013, and 2012
Southern Company and Subsidiary Companies 2014 Annual Report

	2014	2013	2012
		(in millions)	
Consolidated Net Income	**$ 2,031**	$ 1,710	$ 2,415
Other comprehensive income:			
Qualifying hedges:			
Changes in fair value, net of tax of $(6), $-, and $(7), respectively	**(10)**	—	(12)
Reclassification adjustment for amounts included in net income, net of tax of $3, $5, and $7, respectively	**5**	9	11
Marketable securities:			
Change in fair value, net of tax of $-, $(2), and $-, respectively	**—**	(3)	—
Pension and other postretirement benefit plans:			
Benefit plan net gain (loss), net of tax of $(32), $22, and $(2), respectively	**(51)**	36	(3)
Reclassification adjustment for amounts included in net income, net of tax of $2, $4, and $(4), respectively	**3**	6	(8)
Total other comprehensive income (loss)	**(53)**	48	(12)
Dividends on preferred and preference stock of subsidiaries	**(68)**	(66)	(65)
Consolidated Comprehensive Income	**$ 1,910**	$ 1,692	$ 2,338

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2014, 2013, and 2012
Southern Company and Subsidiary Companies 2014 Annual Report

	2014	2013	2012
		(in millions)	
Operating Activities:			
Consolidated net income	$ 2,031	$ 1,710	$ 2,415
Adjustments to reconcile consolidated net income to net cash provided from operating activities —			
Depreciation and amortization, total	2,293	2,298	2,145
Deferred income taxes	709	496	1,096
Investment tax credits	35	302	128
Allowance for equity funds used during construction	(245)	(190)	(143)
Pension, postretirement, and other employee benefits	(515)	131	(398)
Stock based compensation expense	63	59	55
Estimated loss on Kemper IGCC	868	1,180	—
Other, net	(38)	(41)	51
Changes in certain current assets and liabilities —			
-Receivables	(352)	(153)	234
-Fossil fuel stock	408	481	(452)
-Materials and supplies	(67)	36	(97)
-Other current assets	(57)	(11)	(37)
-Accounts payable	267	72	(89)
-Accrued taxes	(105)	(85)	(71)
-Accrued compensation	255	(138)	(28)
-Mirror CWIP	180	—	—
-Other current liabilities	85	(50)	89
Net cash provided from operating activities	5,815	6,097	4,898
Investing Activities:			
Property additions	(5,977)	(5,463)	(4,809)
Investment in restricted cash	(11)	(149)	(280)
Distribution of restricted cash	57	96	284
Nuclear decommissioning trust fund purchases	(916)	(986)	(1,046)
Nuclear decommissioning trust fund sales	914	984	1,043
Cost of removal, net of salvage	(170)	(131)	(149)
Change in construction payables, net	(107)	(126)	(84)
Prepaid long-term service agreement	(181)	(91)	(146)
Other investing activities	(17)	124	19
Net cash used for investing activities	(6,408)	(5,742)	(5,168)
Financing Activities:			
Increase (decrease) in notes payable, net	(676)	662	(30)
Proceeds —			
Long-term debt issuances	3,169	2,938	4,404
Interest-bearing refundable deposit	125	—	150
Preference stock	—	50	—
Common stock issuances	806	695	397
Redemptions and repurchases —			
Long-term debt	(816)	(2,830)	(3,169)
Common stock repurchased	(5)	(20)	(430)
Payment of common stock dividends	(1,866)	(1,762)	(1,693)
Payment of dividends on preferred and preference stock of subsidiaries	(68)	(66)	(65)
Other financing activities	(25)	9	19
Net cash provided from (used for) financing activities	644	(324)	(417)
Net Change in Cash and Cash Equivalents	51	31	(687)
Cash and Cash Equivalents at Beginning of Year	659	628	1,315
Cash and Cash Equivalents at End of Year	$ 710	$ 659	$ 628

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2014 and 2013
Southern Company and Subsidiary Companies 2014 Annual Report

Assets	2014	2013
		(in millions)
Current Assets:		
Cash and cash equivalents	$ 710	$ 659
Receivables —		
Customer accounts receivable	1,090	1,027
Unbilled revenues	432	448
Under recovered regulatory clause revenues	136	58
Other accounts and notes receivable	307	304
Accumulated provision for uncollectible accounts	(18)	(18)
Fossil fuel stock, at average cost	930	1,339
Materials and supplies, at average cost	1,039	959
Vacation pay	177	171
Prepaid expenses	665	278
Deferred income taxes, current	506	143
Other regulatory assets, current	346	207
Other current assets	50	39
Total current assets	6,370	5,614
Property, Plant, and Equipment:		
In service	70,013	66,021
Less accumulated depreciation	24,059	23,059
Plant in service, net of depreciation	45,954	42,962
Other utility plant, net	211	240
Nuclear fuel, at amortized cost	911	855
Construction work in progress	7,792	7,151
Total property, plant, and equipment	54,868	51,208
Other Property and Investments:		
Nuclear decommissioning trusts, at fair value	1,546	1,465
Leveraged leases	743	665
Miscellaneous property and investments	203	218
Total other property and investments	2,492	2,348
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	1,510	1,436
Prepaid pension costs	—	419
Unamortized debt issuance expense	202	139
Unamortized loss on reacquired debt	243	269
Other regulatory assets, deferred	4,334	2,495
Other deferred charges and assets	904	618
Total deferred charges and other assets	7,193	5,376
Total Assets	$ 70,923	$ 64,546

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2014 and 2013
Southern Company and Subsidiary Companies 2014 Annual Report

Liabilities and Stockholders' Equity	2014	2013
		(in millions)
Current Liabilities:		
Securities due within one year	$ 3,333	$ 469
Interest-bearing refundable deposit	275	150
Notes payable	803	1,482
Accounts payable	1,593	1,376
Customer deposits	390	380
Accrued taxes —		
Accrued income taxes	151	13
Other accrued taxes	487	456
Accrued interest	295	251
Accrued vacation pay	223	217
Accrued compensation	576	303
Other regulatory liabilities, current	26	82
Mirror CWIP	271	—
Other current liabilities	544	346
Total current liabilities	8,967	5,525
Long-Term Debt (See accompanying statements)	20,841	21,344
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	11,568	10,563
Deferred credits related to income taxes	192	203
Accumulated deferred investment tax credits	1,208	966
Employee benefit obligations	2,432	1,461
Asset retirement obligations	2,168	2,006
Other cost of removal obligations	1,215	1,275
Other regulatory liabilities, deferred	398	479
Other deferred credits and liabilities	594	585
Total deferred credits and other liabilities	19,775	17,538
Total Liabilities	49,583	44,407
Redeemable Preferred Stock of Subsidiaries (See accompanying statements)	375	375
Redeemable Noncontrolling Interest (See accompanying statements)	39	—
Total Stockholders' Equity (See accompanying statements)	20,926	19,764
Total Liabilities and Stockholders' Equity	$ 70,923	$ 64,546
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, 2014 and 2013
Southern Company and Subsidiary Companies 2014 Annual Report

		2014	2013	2014	2013
		(in millions)		*(percent of total)*	
Long-Term Debt:					
Long-term debt payable to affiliated trusts —					
Variable rate (3.36% at 1/1/15) due 2042		**$ 206**	$ 206		
Total long-term debt payable to affiliated trusts		**206**	206		
Long-term senior notes and debt —					
Maturity	Interest Rates				
2014	3.25% to 4.90%	**—**	428		
2015	0.55% to 5.25%	**2,375**	2,375		
2016	1.95% to 5.30%	**1,360**	1,360		
2017	1.30% to 5.90%	**1,495**	1,095		
2018	2.20% to 5.40%	**850**	850		
2019	2.15% to 5.55%	**1,175**	825		
2020 through 2051	1.63% to 6.38%	**10,574**	9,973		
Variable rate (1.29% at 1/1/14) due 2014		**—**	11		
Variable rates (0.77% to 1.17% at 1/1/15) due 2015		**775**	525		
Variable rates (0.56% to 0.63% at 1/1/15) due 2016		**450**	450		
Total long-term senior notes and debt		**19,054**	17,892		
Other long-term debt —					
Pollution control revenue bonds —					
Maturity	Interest Rates				
2019	4.55%	**25**	25		
2022 through 2049	0.28% to 6.00%	**1,466**	1,453		
Variable rates (0.03% to 0.04% at 1/1/15) due 2015		**152**	54		
Variable rate (0.04% at 1/1/15) due 2016		**4**	4		
Variable rate (0.04% to 0.06% at 1/1/15) due 2017		**36**	36		
Variable rate (0.04% at 1/1/14) due 2018		**—**	19		
Variable rates (0.01% to 0.09% at 1/1/15) due 2020 to 2052		**1,566**	1,642		
Plant Daniel revenue bonds (7.13%) due 2021		**270**	270		
FFB loans (3.00% to 3.86%) due 2044		**1,200**	—		
Total other long-term debt		**4,719**	3,503		
Capitalized lease obligations		**159**	163		
Unamortized debt premium		**69**	79		
Unamortized debt discount		**(33)**	(30)		
Total long-term debt (annual interest requirement — $857 million)		**24,174**	21,813		
Less amount due within one year		**3,333**	469		
Long-term debt excluding amount due within one year		**20,841**	21,344	**49.4%**	51.5%

CONSOLIDATED STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2014 and 2013
Southern Company and Subsidiary Companies 2014 Annual Report

	2014	2013	2014	2013
	(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 — 5.20% to 5.83%				
Authorized — 28 million shares				
Outstanding — 12 million shares: $25 stated value	**294**	294		
Total redeemable preferred stock of subsidiaries (annual dividend requirement — $20 million)	**375**	375	**0.9**	0.9
Redeemable Noncontrolling Interest	**39**	—	**0.1**	—
Common Stockholders' Equity:				
Common stock, par value $5 per share —	**4,539**	4,461		
Authorized — 1.5 billion shares				
Issued — 2014: 909 million shares				
— 2013: 893 million shares				
Treasury — 2014: 0.7 million shares				
— 2013: 5.7 million shares				
Paid-in capital	**5,955**	5,362		
Treasury, at cost	**(26)**	(250)		
Retained earnings	**9,609**	9,510		
Accumulated other comprehensive loss	**(128)**	(75)		
Total common stockholders' equity	**19,949**	19,008	**47.3**	45.8
Preferred and Preference Stock of Subsidiaries and Noncontrolling Interest:				
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	**343**	343		
— 5.63% to 6.50% — 14 million shares (non-cumulative)				
Outstanding — $100 par or stated value	**368**	368		
— 5.60% to 6.50% — 4 million shares (non-cumulative)				
Noncontrolling Interest	**221**	—		
Total preferred and preference stock of subsidiaries and noncontrolling interest (annual dividend requirement — $48 million)	**977**	756	**2.3**	1.8
Total stockholders' equity	**20,926**	19,764		
Total Capitalization	**$ 42,181**	$ 41,483	**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, 2014, 2013, and 2012
Southern Company and Subsidiary Companies 2014 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 Interest	Total
	Issued	Treasury	Par Value	Paid-In Capital	Treasury	Retained Earnings				
	(in thousands)						*(in millions)*			
Balance at December 31, 2011	865,664	(539)	$4,328	$ 4,410	$ (17)	$ 8,968	$ (111)	$ 707	$ —	$ 18,285
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	2,350	—	—	—	2,350
Other comprehensive income (loss)	—	—	—	—	—	—	(12)	—	—	(12)
Stock issued	12,139	—	61	336	—	—	—	—	—	397
Stock repurchased, at cost	—	(9,440)	—	—	(430)	—	—	—	—	(430)
Stock-based compensation	—	—	—	106	—	—	—	—	—	106
Cash dividends of $1.9425 per share	—	—	—	—	—	(1,693)	—	—	—	(1,693)
Other	—	(56)	—	3	(3)	1	—	—	—	1
Balance at December 31, 2012	877,803	(10,035)	4,389	4,855	(450)	9,626	(123)	707	—	19,004
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	1,644	—	—	—	1,644
Other comprehensive income (loss)	—	—	—	—	—	—	48	—	—	48
Stock issued	14,930	4,443	72	441	203	—	—	49	—	765
Stock-based compensation	—	—	—	65	—	—	—	—	—	65
Cash dividends of $2.0125 per share	—	—	—	—	—	(1,762)	—	—	—	(1,762)
Other	—	(55)	—	1	(3)	2	—	—	—	—
Balance at December 31, 2013	**892,733**	**(5,647)**	**4,461**	**5,362**	**(250)**	**9,510**	**(75)**	**756**	**—**	**19,764**
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	**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 interest	—	—	—	—	—	—	—	—	**221**	**221**
Net income attributable to noncontrolling interest	—	—	—	—	—	—	—	—	**(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**

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

Index to the Notes to Financial Statements

Note		Page
1	Summary of Significant Accounting Polices	II-54
2	Retirement Benefits	II-63
3	Contingencies and Regulatory Matters	II-76
4	Joint Ownership Agreements	II-94
5	Income Taxes	II-94
6	Financing	II-98
7	Commitments	II-103
8	Common Stock	II-105
9	Nuclear Insurance	II-107
10	Fair Value Measurements	II-108
11	Derivatives	II-112
12	Segment and Related Information	II-117
13	Quarterly Financial Information (Unaudited)	II-119

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

The Southern Company (Southern Company or the Company) is the parent company of four traditional operating companies, Southern Power, SCS, SouthernLINC Wireless, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, and other direct and indirect subsidiaries. The traditional 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. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants.

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. All material intercompany transactions have been eliminated in consolidation.

The traditional operating companies, Southern Power, and certain of their subsidiaries are subject to regulation by the FERC, and the traditional operating companies are also subject to regulation by their respective state PSCs. The companies follow GAAP in the U.S. and comply with the accounting policies and practices prescribed by their respective 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

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. Southern Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

Regulatory Assets and Liabilities

The traditional operating companies are subject to the provisions of the Financial Accounting Standards Board in accounting for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

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

	2014	2013	Note
	(in millions)		
Retiree benefit plans	$ 3,469	$ 1,760	(a,p)
Deferred income tax charges	1,458	1,376	(b)
Loss on reacquired debt	267	293	(c)
Fuel-hedging-asset	202	58	(d,p)
Deferred PPA charges	185	180	(e,p)
Vacation pay	177	171	(f,p)
Under recovered regulatory clause revenues	157	70	(g)
Kemper IGCC regulatory assets	148	76	(h)
Asset retirement obligations-asset	119	145	(b,p)
Nuclear outage	99	78	(g)
Property damage reserves-asset	98	37	(i)
Cancelled construction projects	67	70	(j)
Environmental remediation-asset	64	62	(k,p)
Deferred income tax charges — Medicare subsidy	57	65	(l)
Other regulatory assets	195	222	(m)
Other cost of removal obligations	(1,229)	(1,289)	(b)
Kemper regulatory liability (Mirror CWIP)	(271)	(91)	(h)
Deferred income tax credits	(192)	(203)	(b)
Property damage reserves-liability	(181)	(191)	(n)
Asset retirement obligations-liability	(130)	(139)	(b,p)
Other regulatory liabilities	(95)	(126)	(o)
Total regulatory assets (liabilities), net	$ 4,664	$ 2,624	

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 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 70 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities. At December 31, 2014, other cost of removal obligations included $29 million that will be amortized over the two-year period from January 2015 through December 2016 in accordance with Georgia Power's 2013 ARP. See Note 3 under "Retail Regulatory Matters – Georgia Power – Rate Plans" for additional information. At December 31, 2014, other cost of removal obligations included $8.4 million recorded as authorized by the Florida PSC in the Settlement Agreement approved in December 2013 (Gulf Power Settlement Agreement).

(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 the energy cost recovery clause.

(e) Recovered over the life of the PPA for periods up to nine 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 over periods not exceeding 10 years.

(h) For additional information, see Note 3 under "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities."

(i) Recorded and recovered or amortized as approved or accepted by the appropriate state PSCs over periods generally not exceeding eight years.

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

(k) Recovered through the environmental cost recovery clause when the remediation is performed.

(l) Recovered and amortized as approved by the appropriate state PSCs over periods not exceeding 15 years.

(m) Comprised of numerous immaterial components including property taxes, generation site selection/evaluation costs, demand side management cost deferrals, regulatory deferrals, building leases, net book value of retired generating units, Plant Daniel Units 3 and 4 regulatory assets, and other miscellaneous assets. These costs are recorded and recovered or amortized as approved by the appropriate state PSC over periods generally not exceeding 10 years or, as applicable, over the remaining life of the asset but not beyond 2031.

(n) Recovered as storm restoration and potential reliability-related expenses are incurred as approved by the appropriate state PSCs.

(o) Comprised of numerous immaterial components including over-recovered regulatory clause revenues, fuel-hedging liabilities, mine reclamation and remediation liabilities, PPA credits, nuclear disposal fees, and other liabilities that are recorded and recovered or amortized as approved by the appropriate state PSCs generally over periods not exceeding 10 years.

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

In the event that a portion of a traditional operating company'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 operating 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 – Alabama Power," "Retail Regulatory Matters – Georgia Power," 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. Electric rates for the traditional operating companies 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.

Southern Company's electric utility subsidiaries 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 operating companies 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. Credits amortized in this manner amounted to $22 million in 2014, $16 million in 2013, and $23 million in 2012. At December 31, 2014, all ITCs available to reduce federal income taxes payable had not been utilized. The remaining ITCs will be carried forward and utilized in future years. Additionally, several subsidiaries have state ITCs, which are recognized in the period in which the credit is claimed on the state income tax return. A portion of the state ITCs available to reduce state income taxes payable was not utilized currently and will be carried forward and utilized in future years.

Under the American Recovery and Reinvestment Act of 2009 and the American Taxpayer Relief Act of 2012 (ATRA), 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. Credits amortized in this manner amounted to $11.4 million in 2014, $5.5 million in 2013, and $2.6 million in 2012. Also, Southern Power received cash related to federal ITCs under the renewable energy incentives of $74 million, $158 million, and $45 million for the years ended December 31, 2014, 2013, and 2012, respectively, which had a material impact on cash flows. 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. The tax benefit of the related basis differences reduced income tax expense by $48 million in 2014, $31 million in 2013, and $8 million in 2012.

In accordance with accounting standards related to the uncertainty in income taxes, 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:

	2014	2013
	(in millions)	
Generation	$ 37,892	$ 35,360
Transmission	9,884	9,289
Distribution	17,123	16,499
General	4,198	3,958
Plant acquisition adjustment	123	123
Utility plant in service	69,220	65,229
Information technology equipment and software	244	242
Communications equipment	439	437
Other	110	113
Other plant in service	793	792
Total plant in service	$ 70,013	$ 66,021

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,	
	2014	2013
	(in millions)	
Office building	$ 61	$ 61
Nitrogen plant	83	83
Computer-related equipment	60	62
Gas pipeline	6	6
Less: Accumulated amortization	(49)	(48)
Balance, net of amortization	$ 161	$ 164

The amount of non-cash property additions recognized for the years ended December 31, 2014, 2013, and 2012 was $528 million, $411 million, and $524 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, 2014, 2013, and 2012 was $25 million, $107 million, and $14 million, respectively.

Acquisitions

Southern Power acquires generation assets as part of its overall growth strategy. Southern Power accounts for business acquisitions from non-affiliates as business combinations. Accordingly, Southern Power has included these operations in the consolidated financial statements from the respective date of acquisition. The purchase price, including contingent consideration, if any, of each acquisition was allocated based on the fair value of the identifiable assets and liabilities. Assets acquired that do not meet the definition of a business in accordance with GAAP are accounted for as asset acquisitions. The purchase price of each asset acquisition was allocated based on the relative fair value of assets acquired. Any due diligence or transition costs incurred by Southern Power for successful or potential acquisitions have been expensed as incurred.

Acquisitions entered into or made by Southern Power during 2014 and 2013 are detailed in the table below:

	MW Capacity	Percentage Ownership	Year of Operation	Party Under PPA Contract for Plant Output	PPA Contract Period	Purchase Price
						(millions)
SG2 Imperial Valley, LLC [a]	150	51%	2014	San Diego Gas & Electric Company	25 years	$504.7 [c]
Macho Springs Solar LLC [b]	50	90	2014	El Paso Electric Company	20 years	$130.0 [d]
Adobe Solar, LLC [b]	20	90	2014	Southern California Edison Company	20 years	$96.2 [d]
Campo Verde Solar, LLC [b][e]	139	90	2013	San Diego Gas & Electric Company	20 years	$136.6 [d]

(a) This acquisition was made by Southern Power through its subsidiaries Southern Renewable Partnerships, LLC and SG2 Holdings, LLC. SG2 Holdings, LLC is jointly-owned by Southern Power and First Solar, Inc.

(b) This acquisition was made by Southern Power and Turner Renewable Energy, LLC through Southern Turner Renewable Energy, LLC.

(c) Reflects Southern Power's portion of the purchase price.

(d) Reflects 100% of the purchase price, including Turner Renewable Energy, LLC's 10% equity contribution.

(e) Under an engineering, procurement, and construction agreement, an additional $355.5 million was paid to a subsidiary of First Solar, Inc. to complete the construction of the solar facility.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.1% in 2014, 3.3% in 2013, and 3.2% in 2012. Depreciation studies are conducted periodically to update the composite rates. These studies are filed with the respective state PSC and the FERC for the traditional operating companies. Accumulated depreciation for utility plant in service totaled $23.5 billion and $22.5 billion at December 31, 2014 and 2013, 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 now 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. The book value of plant-in-service as of December 31, 2014 that is depreciated on a units-of-production basis was approximately $470.2 million.

In 2009, the Georgia PSC approved an accounting order allowing Georgia Power to amortize a portion of its regulatory liability related to other cost of removal obligations. Under the terms of Georgia Power's Alternate Rate Plan for the years 2011 through 2013 (2010 ARP), Georgia Power amortized approximately $31 million annually of the remaining regulatory liability related to other cost of removal obligations over the three years ended December 31, 2013. Under the terms of the 2013 ARP, an additional $14 million is being amortized annually by Georgia Power over the three years ending December 31, 2016. See Note 3 under "Retail Regulatory Matters – Georgia Power – Rate Plans" for additional information.

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 25 years. Accumulated depreciation for other plant in service totaled $533 million and $513 million at December 31, 2014 and 2013, respectively.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) are computed as the present value of the 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. Each traditional operating company has received accounting guidance from the various state PSCs allowing the continued accrual of other future 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.

The liability for AROs primarily relates to the decommissioning of the Southern Company system's nuclear facilities, Plants Farley, Hatch, and Vogtle. In addition, the Southern Company system has retirement obligations related to various landfill sites, ash ponds, asbestos removal, mine reclamation, and disposal of polychlorinated biphenyls in certain transformers. The Southern Company system also has identified retirement obligations related to certain 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 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 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:

	2014	2013
	(in millions)	
Balance at beginning of year	$ 2,018	$ 1,757
Liabilities incurred	18	6
Liabilities settled	(17)	(16)
Accretion	102	97
Cash flow revisions	80	174
Balance at end of year	$ 2,201	$ 2,018

The cash flow revisions in 2014 are primarily related to Alabama Power's and SEGCO's AROs associated with asbestos at their steam generation facilities. The cash flow revisions in 2013 are primarily related to revisions to the nuclear decommissioning ARO based on Alabama Power's updated decommissioning study and Georgia Power's updated estimates for ash ponds in connection with the retirement of certain coal-fired generating units.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in landfills and surface impoundments at active generating power plants. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the traditional operating companies' ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain; however, Southern Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $860 million and ongoing post-closure care of approximately $140 million. Certain of the traditional operating companies have previously recorded AROs associated with ash ponds of $506 million, or $468 million on a nominal dollar basis, based on existing state requirements. During 2015, the traditional operating companies will record AROs for any incremental estimated closure costs resulting from acceleration in the timing of any currently planned closures and for differences between existing state requirements and the requirements of the CCR Rule. Southern Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

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, 2014 and 2013, approximately $51 million and $32 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 $52 million and $33 million at December 31, 2014 and 2013, 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, 2014, investment securities in the Funds totaled $1.5 billion, consisting of equity securities of $886 million, debt securities of $638 million, and $19 million of other securities. At December 31, 2013, investment securities in the Funds totaled $1.5 billion, consisting of equity securities of $896 million, debt securities of $528 million, and $40 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 $913 million, $1.0 billion, and $1.0 billion in 2014, 2013, and 2012, respectively, all of which were reinvested. For 2014, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $98 million, of which $2 million related to realized gains and $19 million related to unrealized gains and losses related to securities held in the Funds at December 31, 2014. For 2013, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $181 million, of which $5 million related to realized gains and $119 million related to unrealized gains related to securities held in the Funds at December 31, 2013. For 2012, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $137 million, of which $4 million related to realized gains and $75 million related to unrealized gains related to securities held in the Funds at December 31, 2012. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of the securities and purpose for which the securities were acquired.

For Alabama Power, amounts previously recorded in internal reserves are being transferred into the Funds over periods 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, 2014 and 2013, the accumulated provisions for decommissioning were as follows:

	External Trust Funds		Internal Reserves		Total	
	2014	2013	**2014**	2013	**2014**	2013
			(in millions)			
Plant Farley	**$ 754**	$ 713	**$ 21**	$ 21	**$ 775**	$ 734
Plant Hatch	**496**	469	**—**	—	**496**	469
Plant Vogtle Units 1 and 2	**293**	277	**—**	—	**293**	277

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, 2014 based on the most current studies, which were performed in 2013 for Alabama Power's Plant Farley and in 2012 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	2068	2072
		(in millions)	
Site study costs:			
Radiated structures	$ 1,362	$ 549	$ 453
Spent fuel management	—	131	115
Non-radiated structures	80	51	76
Total site study costs	$ 1,442	$ 731	$ 644

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 through 2016 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 periodically review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs. 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

In accordance with regulatory treatment, the traditional operating companies 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 from such allowance, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. Interest related to the construction of new facilities not included in the traditional operating companies' regulated rates is capitalized in accordance with standard interest capitalization requirements. AFUDC and interest capitalized, net of income taxes were 16.0%, 15.0%, and 8.2% of net income for 2014, 2013, and 2012, respectively.

Cash payments for interest totaled $732 million, $759 million, and $803 million in 2014, 2013, and 2012, respectively, net of amounts capitalized of $111 million, $92 million, and $83 million, respectively.

Impairment of Long-Lived Assets and Intangibles

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.

Storm Damage Reserves

Each traditional 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 operating companies accrued $40 million in 2014 and $28 million in 2013. 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 2014 and 2013, there were no such additional accruals. See Note 3 under "Retail Regulatory Matters – Alabama Power – Natural Disaster Reserve" and "Retail 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. The 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:

	2014	2013
	(in millions)	
Net rentals receivable	$ 1,495	$ 1,440
Unearned income	(752)	(775)
Investment in leveraged leases	743	665
Deferred taxes from leveraged leases	(299)	(287)
Net investment in leveraged leases	$ 444	$ 378

A summary of the components of income from the leveraged leases follows:

	2014	2013	2012
		(in millions)	
Pretax leveraged lease income (loss)	$ 24	$ (5)	$ 21
Income tax expense	(9)	2	(8)
Net leveraged lease income (loss)	$ 15	$ (3)	$ 13

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 charged to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the traditional 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.

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 (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 operating companies' 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. See Note 11 for additional information regarding derivatives.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. At December 31, 2014, 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, 2013	$ (36)	$ —	$ (39)	$ (75)
Current period change	(5)	—	(48)	(53)
Balance at December 31, 2014	**$ (41)**	**$ —**	**$ (87)**	**$ (128)**

2. RETIREMENT BENEFITS

Southern 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). In December 2014, certain of the traditional operating companies and other subsidiaries voluntarily contributed an aggregate of $500 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. 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 operating companies fund related other postretirement trusts to the extent required by their respective regulatory commissions. For the year ending December 31, 2015, other postretirement trust contributions are expected to total approximately $19 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2011 for the 2012 plan year using discount rates for the pension plans and the other postretirement benefit plans of 4.98% and 4.88%, respectively, and an annual salary increase of 3.84%.

	2014	2013	2012
Discount rate:			
Pension plans	**4.17%**	5.02%	4.26%
Other postretirement benefit plans	**4.04**	4.85	4.05
Annual salary increase	**3.59**	3.59	3.59
Long-term return on plan assets:			
Pension plans	**8.20**	8.20	8.20
Other postretirement benefit plans	**7.15**	7.13	7.29

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

For purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $636 million and $92 million, respectively.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2014 were as follows:

	Initial Cost Trend Rate	**Ultimate Cost Trend Rate**	**Year That Ultimate Rate is Reached**
Pre-65	9.00%	4.50%	2024
Post-65 medical	6.00	4.50	2024
Post-65 prescription	6.75	4.50	2024

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, 2014 as follows:

	1 Percent Increase	**1 Percent Decrease**
	(in millions)	
Benefit obligation	$ 140	$ (117)
Service and interest costs	6	(5)

Pension Plans

The total accumulated benefit obligation for the pension plans was $10.0 billion at December 31, 2014 and $8.1 billion at December 31, 2013. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 8,863	$ 9,302
Service cost	213	232
Interest cost	435	389
Benefits paid	(382)	(357)
Actuarial (gain) loss	1,780	(703)
Balance at end of year	10,909	8,863
Change in plan assets		
Fair value of plan assets at beginning of year	8,733	7,953
Actual return on plan assets	797	1,098
Employer contributions	542	39
Benefits paid	(382)	(357)
Fair value of plan assets at end of year	9,690	8,733
Accrued liability	$ (1,219)	$ (130)

At December 31, 2014, the projected benefit obligations for the qualified and non-qualified pension plans were $10.3 billion and $617 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's pension plans consist of the following:

	2014	2013
	(in millions)	
Prepaid pension costs	$ —	$ 419
Other regulatory assets, deferred	3,073	1,651
Other current liabilities	(42)	(40)
Employee benefit obligations	(1,177)	(509)
Accumulated OCI	134	64

Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2014 and 2013 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 2015.

	Prior Service Cost	Net (Gain) Loss
	(in millions)	
Balance at December 31, 2014:		
Accumulated OCI	**$ 4**	**$ 130**
Regulatory assets	**51**	**3,022**
Total	**$ 55**	**$ 3,152**
Balance at December 31, 2013:		
Accumulated OCI	$ 5	$ 59
Regulatory assets	75	1,575
Total	$ 80	$ 1,634
Estimated amortization in net periodic pension cost in 2015:		
Accumulated OCI	$ 1	$ 9
Regulatory assets	24	206
Total	$ 25	$ 215

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, 2014 and 2013 are presented in the following table:

	Accumulated OCI	Regulatory Assets
	(in millions)	
Balance at December 31, 2012	$ 125	$ 3,013
Net gain	(52)	(1,145)
Change in prior service costs	—	1
Reclassification adjustments:		
Amortization of prior service costs	(1)	(26)
Amortization of net gain (loss)	(8)	(192)
Total reclassification adjustments	(9)	(218)
Total change	(61)	(1,362)
Balance at December 31, 2013	$ 64	$ 1,651
Net gain	**75**	**1,552**
Change in prior service costs	**—**	**1**
Reclassification adjustments:		
Amortization of prior service costs	**(1)**	**(25)**
Amortization of net gain (loss)	**(4)**	**(106)**
Total reclassification adjustments	**(5)**	**(131)**
Total change	**70**	**1,422**
Balance at December 31, 2014	**$ 134**	**$ 3,073**

Components of net periodic pension cost were as follows:

	2014	2013	2012
		(in millions)	
Service cost	**$ 213**	$ 232	$ 198
Interest cost	**435**	389	393
Expected return on plan assets	**(645)**	(603)	(581)
Recognized net loss	**110**	200	95
Net amortization	**26**	27	30
Net periodic pension cost	**$ 139**	$ 245	$ 135

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, 2014, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2015	$ 522
2016	450
2017	478
2018	499
2019	524
2020 to 2024	2,962

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 1,682	$ 1,872
Service cost	21	24
Interest cost	79	74
Benefits paid	(102)	(94)
Actuarial (gain) loss	300	(200)
Plan amendments	(2)	—
Retiree drug subsidy	8	6
Balance at end of year	1,986	1,682
Change in plan assets		
Fair value of plan assets at beginning of year	901	821
Actual return on plan assets	54	129
Employer contributions	39	39
Benefits paid	(94)	(88)
Fair value of plan assets at end of year	900	901
Accrued liability	$ (1,086)	$ (781)

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's other postretirement benefit plans consist of the following:

	2014	2013
	(in millions)	
Other regulatory assets, deferred	$ 387	$ 109
Other current liabilities	(4)	(4)
Employee benefit obligations	(1,082)	(777)
Other regulatory liabilities, deferred	(21)	(36)
Accumulated OCI	8	1

Presented below are the amounts included in accumulated OCI and net regulatory assets (liabilities) at December 31, 2014 and 2013 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 2015.

	Prior Service Cost	Net (Gain) Loss
	(in millions)	
Balance at December 31, 2014:		
Accumulated OCI	$ —	$ 8
Net regulatory assets (liabilities)	2	364
Total	$ 2	$ 372
Balance at December 31, 2013:		
Accumulated OCI	$ —	$ 1
Net regulatory assets (liabilities)	9	64
Total	$ 9	$ 65
Estimated amortization as net periodic postretirement benefit cost in 2015:		
Accumulated OCI	$ —	$ —
Net regulatory assets (liabilities)	4	17
Total	$ 4	$ 17

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, 2014 and 2013 are presented in the following table:

	Accumulated OCI	Net Regulatory Assets (Liabilities)
	(in millions)	
Balance at December 31, 2012	$ 7	$ 360
Net loss	(6)	(266)
Reclassification adjustments:		
Amortization of transition obligation	—	(5)
Amortization of prior service costs	—	(4)
Amortization of net gain (loss)	—	(12)
Total reclassification adjustments	—	(21)
Total change	(6)	(287)
Balance at December 31, 2013	$ 1	$ 73
Net gain	**7**	**301**
Change in prior service costs	—	**(2)**
Reclassification adjustments:		
Amortization of prior service costs	—	**(4)**
Amortization of net gain (loss)	—	**(2)**
Total reclassification adjustments	—	**(6)**
Total change	**7**	**293**
Balance at December 31, 2014	**$ 8**	**$ 366**

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

	2014	2013	2012
		(in millions)	
Service cost	$ 21	$ 24	$ 21
Interest cost	79	74	85
Expected return on plan assets	(59)	(56)	(60)
Net amortization	6	21	20
Net periodic postretirement benefit cost	$ 47	$ 63	$ 66

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)	
2015	$ 118	$ (10)	$ 108
2016	124	(11)	113
2017	129	(12)	117
2018	132	(13)	119
2019	134	(15)	119
2020 to 2024	670	(79)	591

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.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2014 and 2013, along with the targeted mix of assets for each plan, is presented below:

	Target	2014	2013
Pension plan assets:			
Domestic equity	26%	**30%**	31%
International equity	25	**23**	25
Fixed income	23	**27**	23
Special situations	3	**1**	1
Real estate investments	14	**14**	14
Private equity	9	**5**	6
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	42%	**41%**	40%
International equity	21	**23**	25
Domestic fixed income	24	**26**	24
Global fixed income	4	**3**	4
Special situations	1	**—**	—
Real estate investments	5	**5**	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, 2014 and 2013. 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 and private equity.*** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

The fair values of pension plan assets as of December 31, 2014 and 2013 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 1,704	$ 704	$ —	$ 2,408
International equity*	1,070	986	—	2,056
Fixed income:				
U.S. Treasury, government, and agency bonds	—	699	—	699
Mortgage- and asset-backed securities	—	188	—	188
Corporate bonds	—	1,135	—	1,135
Pooled funds	—	514	—	514
Cash equivalents and other	3	660	—	663
Real estate investments	293	—	1,121	1,414
Private equity	—	—	570	570
Total	$ 3,070	$ 4,886	$ 1,691	$ 9,647
Liabilities:				
Derivatives	$ (2)	$ —	$ —	$ (2)
Total	$ 3,068	$ 4,886	$ 1,691	$ 9,645

* 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, 2013:	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)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 1,433	$ 839	$ —	$ 2,272
International equity*	1,101	1,018	—	2,119
Fixed income:				
U.S. Treasury, government, and agency bonds	—	599	—	599
Mortgage- and asset-backed securities	—	156	—	156
Corporate bonds	—	978	—	978
Pooled funds	—	471	—	471
Cash equivalents and other	1	223	—	224
Real estate investments	260	—	1,000	1,260
Private equity	—	—	571	571
Total	$ 2,795	$ 4,284	$ 1,571	$ 8,650
Liabilities:				
Derivatives	$ —	$ (3)	$ —	$ (3)
Total	$ 2,795	$ 4,281	$ 1,571	$ 8,647

* 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.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2014 and 2013 were as follows:

	2014		2013	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in millions)		
Beginning balance	**$ 1,000**	**$ 571**	$ 841	$ 593
Actual return on investments:				
Related to investments held at year end	**79**	**51**	74	8
Related to investments sold during the year	**33**	**(16)**	30	51
Total return on investments	**112**	**35**	104	59
Purchases, sales, and settlements	**9**	**(36)**	55	(81)
Ending balance	**$ 1,121**	**$ 570**	$ 1,000	$ 571

The fair values of other postretirement benefit plan assets as of December 31, 2014 and 2013 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 147	$ 56	$ —	$ 203
International equity*	36	67	—	103
Fixed income:				
U.S. Treasury, government, and agency bonds	—	29	—	29
Mortgage- and asset-backed securities	—	6	—	6
Corporate bonds	—	39	—	39
Pooled funds	—	41	—	41
Cash equivalents and other	9	27	—	36
Trust-owned life insurance	—	381	—	381
Real estate investments	11	—	37	48
Private equity	—	—	19	19
Total	$ 203	$ 646	$ 56	$ 905

* 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, 2013:	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)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 157	$ 45	$ —	$ 202
International equity*	39	82	—	121
Fixed income:				
U.S. Treasury, government, and agency bonds	—	34	—	34
Mortgage- and asset-backed securities	—	6	—	6
Corporate bonds	—	35	—	35
Pooled funds	—	46	—	46
Cash equivalents and other	—	19	—	19
Trust-owned life insurance	—	369	—	369
Real estate investments	10	—	36	46
Private equity	—	—	20	20
Total	$ 206	$ 636	$ 56	$ 898

* 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.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2014 and 2013 were as follows:

	2014		2013	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in millions)		
Beginning balance	$ 36	$ 20	$ 30	$ 21
Actual return on investments:				
Related to investments held at year end	1	1	3	—
Related to investments sold during the year	—	(1)	1	2
Total return on investments	1	—	4	2
Purchases, sales, and settlements	—	(1)	2	(3)
Ending balance	$ 37	$ 19	$ 36	$ 20

Employee Savings Plan

Southern 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 2014, 2013, and 2012 were $87 million, $84 million, and $82 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

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.

Insurance Recovery

Mirant Corporation (Mirant) was an energy company with businesses that included independent power projects and energy trading and risk management companies in the U.S. and other countries. Mirant was a wholly-owned subsidiary of Southern Company until its initial public offering in 2000. In 2001, Southern Company completed a spin-off to its stockholders of its remaining ownership, and Mirant became an independent corporate entity.

In 2003, Mirant and certain of its affiliates filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code. In 2005, Mirant, as a debtor in possession, and the unsecured creditors' committee filed a complaint against Southern Company. Later in 2005, this complaint was transferred to MC Asset Recovery, LLC (MC Asset Recovery) as part of Mirant's plan of reorganization. In 2009, Southern Company entered into a settlement agreement with MC Asset Recovery to resolve this action. The settlement included an agreement where Southern Company paid MC Asset Recovery $202 million. Southern Company filed an insurance claim in 2009 to recover a portion of this settlement and received payments from its insurance provider of $25 million in June 2012 and $15 million in December 2013. Additionally, legal fees related to these insurance settlements totaled approximately $6 million in 2012 and $4 million in 2013. As a result, the net reduction to expense presented as MC Asset Recovery insurance settlement in the statement of income was approximately $19 million in 2012 and $11 million in 2013.

Environmental Matters

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against Alabama Power and Georgia Power alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including units co-owned by Gulf Power and Mississippi Power. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. The case against Georgia Power (including claims related to a unit co-owned by Gulf Power) has been administratively closed in the U.S. District Court for the Northern District of Georgia since 2001. The case against Alabama Power (including claims involving a unit co-owned by Mississippi Power) has been actively litigated in the U.S. District Court for the Northern District of Alabama, resulting in a settlement in 2006 of the alleged NSR violations at Plant Miller; voluntary dismissal of certain claims by the EPA; and a grant of summary judgment for Alabama Power on all remaining claims and dismissal of the case with prejudice in 2011. In September 2013, the U.S. Court of Appeals for the Eleventh Circuit affirmed in part and reversed in part the 2011 judgment in favor of Alabama Power, and the case has been transferred back to the U.S. District Court for the Northern District of Alabama for further proceedings.

Southern Company believes the traditional operating companies complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of these matters cannot be determined at this time.

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 properties. The traditional operating companies have each received authority from their respective state PSCs to recover approved environmental compliance costs through regulatory mechanisms. These rates are adjusted annually or as necessary within limits approved by the state PSCs.

Georgia Power's environmental remediation liability as of December 31, 2014 was $22 million. Georgia Power has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a site in Brunswick, Georgia on the CERCLA National Priorities List. The parties have completed the removal of wastes from the

Brunswick site as ordered by the EPA. Additional cleanup and claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites are anticipated.

Georgia Power and numerous other entities have been designated by the EPA as PRPs at the Ward Transformer Superfund site located in Raleigh, North Carolina. In 2011, the EPA issued a Unilateral Administrative Order (UAO) to Georgia Power and 22 other parties, ordering specific remedial action of certain areas at the site. Later in 2011, Georgia Power filed a response with the EPA stating it has sufficient cause to believe it is not a liable party under CERCLA. The EPA notified Georgia Power in 2011 that it is considering enforcement options against Georgia Power and other non-complying UAO recipients. If the EPA pursues enforcement actions and the court determines that a respondent failed to comply with the UAO without sufficient cause, the EPA may also seek civil penalties of up to $37,500 per day for the violation and punitive damages of up to three times the costs incurred by the EPA as a result of the party's failure to comply with the UAO.

In addition to the EPA's action at this site, Georgia Power, along with many other parties, was sued in a private action by several existing PRPs for cost recovery related to the removal action. In February 2013, the U.S. District Court for the Eastern District of North Carolina Western Division granted Georgia Power's summary judgment motion, ruling that Georgia Power has no liability in the private action. In May 2013, the plaintiffs appealed the U.S. District Court for the Eastern District of North Carolina Western Division's order to the U.S. Court of Appeals for the Fourth Circuit.

The ultimate outcome of these matters will depend upon the success of defenses asserted, the ultimate number of PRPs participating in the cleanup, and numerous other factors and cannot be determined at this time; however, as a result of Georgia Power's regulatory treatment for environmental remediation expenses, these matters are not expected to have a material impact on Southern Company's financial statements.

Gulf Power's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $48 million as of December 31, 2014. These estimated costs relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at Gulf Power 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.

The final outcome of these matters cannot be determined at this time. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, management does not believe that additional liabilities, if any, at these sites would be material to the 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.

As a result of the first lawsuit, Georgia Power recovered approximately $27 million, based on its ownership interests, and Alabama Power recovered approximately $17 million, representing the vast majority of the Southern Company system's direct costs of the expansion of spent nuclear fuel storage facilities at Plants Farley and Hatch and Plant Vogtle Units 1 and 2 from 1998 through 2004. In 2012, Alabama Power credited the award to cost of service for the benefit of customers. Also in 2012, Georgia Power credited the award to accounts where the original costs were charged and used it to reduce rate base, fuel, and cost of service for the benefit of customers.

On December 12, 2014, the Court of Federal Claims entered a judgment in favor of Georgia Power and Alabama Power in the second spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. Georgia Power was awarded approximately $18 million, based on its ownership interests, and Alabama Power was awarded approximately $26 million. No amounts have been recognized in the financial statements as of December 31, 2014. The final outcome of this matter cannot be determined at this time; however, no material impact on Southern Company's net income is expected.

On March 4, 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. 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, 2014 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.

Retail Regulatory Matters

Alabama Power

Rate RSE

Alabama Power's Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate 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 weighted cost of equity (WCE) range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range. Prior to 2014, retail rates remained unchanged when the retail ROE was projected to be between 13.0% and 14.5%.

During 2013, the Alabama PSC held public proceedings regarding the operation and utilization of Rate RSE. In August 2013, the Alabama PSC voted to issue a report on Rate RSE that found that Alabama Power's Rate RSE mechanism continues to be just and reasonable to customers and Alabama Power, but recommended Alabama Power modify Rate RSE as follows:

- Eliminate the provision of Rate RSE establishing an allowed range of ROE.
- Eliminate the provision of Rate RSE limiting Alabama Power's capital structure to an allowed equity ratio of 45%.
- Replace these two provisions with a provision that establishes rates based upon the WCE range of 5.75% to 6.21%, with an adjusting point of 5.98%. If calculated under the previous Rate RSE provisions, the resulting WCE would range from 5.85% to 6.53%, with an adjusting point of 6.19%.
- Provide 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.

Substantially all other provisions of Rate RSE were unchanged.

In August 2013, Alabama Power filed its consent to these recommendations with the Alabama PSC. The changes became effective for calendar year 2014. In November 2013, Alabama Power made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2014; projected earnings were within the specified WCE range and, therefore, retail rates under Rate RSE remained unchanged for 2014. In 2012 and 2013, retail rates under Rate RSE remained unchanged from 2011. Under the terms of Rate RSE, the maximum possible increase for 2015 is 5.00%.

On December 1, 2014, Alabama Power submitted the required annual filing under Rate RSE to the Alabama PSC. The Rate RSE increase was 3.49%, or $181 million annually, effective January 1, 2015. The revenue adjustment includes the performance based adder of 0.07%. Under the terms of Rate RSE, the maximum increase for 2016 cannot exceed 4.51%.

Rate CNP

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 4, 2014, 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, 2014 through March 31, 2015. It is anticipated that no adjustment will be made to Rate CNP PPA in 2015. As of December 31, 2014, Alabama Power had an under recovered certificated PPA balance of $56 million, of which $27 million is included in under recovered regulatory clause revenues and $29 million is included in deferred under recovered regulatory clause revenues in the balance sheet.

In 2011, the Alabama PSC approved and certificated a PPA of approximately 200 MWs of electricity from wind-powered generating facilities that became operational in 2012. In 2012, the Alabama PSC approved and certificated a second PPA of approximately 200 MWs of electricity from other wind-powered generating facilities which became operational in 2014. The terms of the PPAs permit Alabama Power to use the energy and retire the associated environmental attributes in service of its customers or to sell the environmental attributes, separately or bundled with energy. Alabama Power has elected the normal purchase normal sale (NPNS) scope exception under the derivative accounting rules for its two wind PPAs, which total approximately 400 MWs. The NPNS exception allows the PPAs to be recorded at a cost, rather than fair value, basis. The industry's application of the NPNS exception to certain physical forward transactions in nodal markets was previously under review by the SEC at the request of the electric utility industry. In June 2014, the SEC requested the Financial Accounting

Standards Board to address the issue through the Emerging Issues Task Force (EITF). Any accounting decisions will now be subject to EITF deliberations. The outcome of the EITF's deliberations cannot be determined at this time. If Alabama Power is ultimately required to record these PPAs at fair value, an offsetting regulatory asset or regulatory liability will be recorded.

Rate CNP Environmental allows for the recovery of Alabama Power's retail costs associated with environmental laws, regulations, or other such mandates. Rate CNP Environmental is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. There was no adjustment to Rate CNP Environmental in 2014. In August 2013, the Alabama PSC approved Alabama Power's petition requesting a revision to Rate CNP Environmental that allows recovery of costs related to pre-2005 environmental assets previously being recovered through Rate RSE. The Rate CNP Environmental increase effective January 1, 2015 was 1.5%, or $75 million annually, based upon projected billings. As of December 31, 2014, Alabama Power had an under recovered environmental clause balance of $49 million, of which $47 million is included in under recovered regulatory clause revenues and $2 million is included in deferred under recovered regulatory clause revenues in the balance sheet.

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 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 2014, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2015 the energy cost recovery rates which began in 2011. Therefore, the Rate ECR factor as of January 1, 2015 remained at 2.681 cents per KWH. Effective with billings beginning in January 2016, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

Alabama Power's over recovered fuel costs at December 31, 2014 totaled $47 million as compared to over recovered fuel costs of $42 million at December 31, 2013. At December 31, 2014, $47 million is included in deferred over recovered regulatory clause revenues. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery or return of fuel costs.

Rate NDR

Based on an order from the Alabama PSC, 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.

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 would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement.

As part of its environmental compliance strategy, Alabama Power plans to retire Plant Gorgas Units 6 and 7. These units represent 200 MWs of Alabama Power's approximately 12,200 MWs of generating capacity. Alabama Power also plans to cease 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. Additionally, Alabama Power expects to cease using coal at Plant Barry Unit 3 (225 MWs) and Plant Greene County Units 1 and 2 (300 MWs) and begin operating those units solely on natural gas. These plans are expected to be effective no later than April 2016.

In accordance with an accounting order from the Alabama PSC, Alabama Power will transfer the unrecovered plant asset balances to a regulatory asset at their respective retirement dates. The regulatory asset will be amortized through Rate CNP Environmental over the remaining useful lives, as established prior to the decision for retirement. As a result, these decisions will not have a significant impact on Southern Company's financial statements.

Nuclear Waste Fund Accounting Order

In November 2013, the U.S. District Court for the District of Columbia ordered the DOE to cease collecting spent fuel depositary fees from nuclear power plant operators until such time as the DOE either complies with the Nuclear Waste Policy Act of 1982 or until the U.S. Congress enacts an alternative waste management plan. In accordance with the court's order, the DOE submitted a proposal to the U.S. Congress to change the fee to zero. On March 18, 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied the DOE's request for rehearing of the November 2013 panel decision ordering that the DOE propose the nuclear waste fund fee be changed to zero. The DOE formally set the fee to zero effective May 16, 2014.

On August 5, 2014, the Alabama PSC issued an order to provide for the continued recovery from customers of amounts associated with the permanent disposal of nuclear waste from the operation of Plant Farley. In accordance with the order, effective May 16, 2014, Alabama Power is authorized to recover from customers an amount equal to the prior fee and to record the amounts in a regulatory liability account (approximately $14 million annually). At December 31, 2014, Alabama Power recorded an $8 million regulatory liability which is included in other regulatory liabilities deferred in the balance sheet. Upon the DOE meeting the requirements of the Nuclear Waste Policy Act of 1982 and a new spent fuel depositary fee being put in place, the accumulated balance in the regulatory liability account will be available for purposes of the associated cost responsibility. In the event the balance is later determined to be more than needed, those amounts would be used for the benefit of customers, subject to the approval of the Alabama PSC. The ultimate outcome of this matter cannot be determined at this time.

Compliance and Pension Cost Accounting Order

In 2012, the Alabama PSC approved an accounting order to defer to a regulatory asset account certain compliance-related operations and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in operations expense related to pension cost for 2013. These deferred costs would have been amortized over a three-year period beginning in January 2015. The compliance related expenditures were related to (i) standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation, (ii) cyber security requirements issued by the NRC, and (iii) NRC guidance addressing the readiness at nuclear facilities within the U.S. for severe events.

On November 3, 2014, the Alabama PSC issued an accounting order authorizing Alabama Power to fully amortize the balances in certain regulatory asset accounts, including the $28 million of compliance and pension costs accumulated at December 31, 2014. This amortization expense was offset by the amortization of the regulatory liability for other cost of removal obligations. See "Cost of Removal Accounting Order" herein for additional information. The cost of removal accounting order requires Alabama Power to terminate, as of December 31, 2014, the regulatory asset accounts created pursuant to the compliance and pension cost accounting order. Consequently, Alabama Power will not defer any expenditures in 2015, 2016, and 2017 related to critical electric infrastructure and domestic nuclear facilities under these orders.

Non-Nuclear Outage Accounting Order

In August 2013, the Alabama PSC approved an accounting order to defer to a regulatory asset account certain operations and maintenance expenses associated with planned outages at non-nuclear generation facilities in 2014 and to amortize those expenses over a three-year period beginning in 2015.

On November 3, 2014, the Alabama PSC issued an accounting order authorizing Alabama Power to fully amortize the balances in certain regulatory asset accounts, including the $95 million of non-nuclear outage costs accumulated at December 31, 2014. This amortization expense was reflected in other operations and maintenance and was offset by the amortization of the regulatory liability for other cost of removal obligations. See "Cost of Removal Accounting Order" herein for additional information. The cost of removal accounting order requires Alabama Power to terminate, as of December 31, 2014, the regulatory asset accounts created pursuant to the non-nuclear outage accounting order.

Cost of Removal Accounting Order

In accordance with an accounting order issued on November 3, 2014 by the Alabama PSC, at December 31, 2014, Alabama Power 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 account balances amortized 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, as discussed herein.

Non-Environmental Federal Mandated Costs Accounting Order

On December 9, 2014, pending the development of a new cost recovery mechanism, the Alabama PSC issued an accounting order authorizing the deferral as a regulatory asset of up to $50 million of costs associated with non-environmental federal mandates that would otherwise impact rates in 2015.

On February 17, 2015, Alabama Power filed a proposed modification to Rate CNP Environmental with the Alabama PSC to include compliance costs for both environmental and non-environmental mandates. The non-environmental costs that would be recovered through the revised mechanism concern laws, regulations, and other mandates directed at the utility industry involving the security, reliability, safety, sustainability, or similar considerations impacting Alabama Power's facilities or operations. If approved as requested, the effective date for the revised mechanism would be March 20, 2015, upon which the regulatory asset balance would be reclassified to the under recovered balance for Rate CNP Environmental, and the related customer rates would not become effective before January 2016. The ultimate outcome of this matter cannot be determined at this time.

Georgia Power

Rate Plans

In December 2013, the Georgia PSC voted to approve the 2013 ARP. The 2013 ARP reflects the settlement agreement among Georgia Power, the Georgia PSC's Public Interest Advocacy Staff, and 11 of the 13 intervenors, which was filed with the Georgia PSC in November 2013.

On January 1, 2014, in accordance with the 2013 ARP, Georgia Power increased its tariffs as follows: (1) traditional base tariff rates by approximately $80 million; (2) Environmental Compliance Cost Recovery (ECCR) tariff by approximately $25 million; (3) Demand-Side Management (DSM) tariffs by approximately $1 million; and (4) Municipal Franchise Fee (MFF) tariff by approximately $4 million, for a total increase in base revenues of approximately $110 million.

On February 19, 2015, in accordance with the 2013 ARP, the Georgia PSC approved adjustments to traditional base, ECCR, DSM, and MFF tariffs effective January 1, 2015 as follows:

- Traditional base tariffs by approximately $107 million to cover additional capacity costs;
- ECCR tariff by approximately $23 million;
- DSM tariffs by approximately $3 million; and
- MFF tariff by approximately $3 million to reflect the adjustments above.

The sum of these adjustments resulted in a base revenue increase of approximately $136 million in 2015.

The 2016 base rate increase, which was approved in the 2013 ARP, will be determined through a compliance filing expected to be filed in late 2015, and will be subject to review by the Georgia PSC.

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. However, if at any time during the term of the 2013 ARP, Georgia Power projects that its retail earnings will be below 10.00% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff that would be used to adjust Georgia Power's earnings back to a 10.00% retail ROE. The Georgia PSC would have 90 days to rule on Georgia Power's request.

The ICR tariff will expire at the earlier of January 1, 2017 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, Georgia Power may file a full rate case. In 2014, Georgia Power's retail ROE exceeded 12.00%, and Georgia Power expects to refund to retail customers approximately $13 million in 2015, subject to review and approval by the Georgia PSC.

Except as provided above, Georgia Power will not file for a general base rate increase while the 2013 ARP is in effect. Georgia Power is required to file a general rate case by July 1, 2016, in response to which the Georgia PSC would be expected to determine whether the 2013 ARP should be continued, modified, or discontinued.

Integrated Resource Plans

In July 2013, the Georgia PSC approved Georgia Power's latest triennial Integrated Resource Plan (2013 IRP) including Georgia Power's request to decertify 16 coal- and oil-fired units totaling 2,093 MWs. Several factors, including the cost to comply with existing and future environmental regulations, recent and forecasted economic conditions, and lower natural gas prices, contributed to the decision to close these units.

Plant Branch Units 3 and 4 (1,016 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) will be decertified and retired by April 16, 2015, the compliance date of the Mercury and Air Toxics Standards (MATS) rule. The decertification date of Plant Branch Unit 1 (250 MWs) was extended from December 31, 2013 as specified in the final order in the 2011 Integrated Resource Plan Update (2011 IRP Update) to coincide with the decertification date of Plant Branch Units 3 and 4. The decertification and retirement of Plant Kraft Units 1 through 4 (316 MWs) were also approved and will be effective by April 16, 2016, based on a one-year extension of the MATS rule compliance date that was approved by the State of Georgia Environmental Protection Division in September 2013 to allow for necessary transmission system reliability improvements. In July 2013, the Georgia PSC approved the switch to natural gas as the primary fuel for Plant Yates Units 6 and 7. In September 2013, Plant Branch Unit 2 (319 MWs) was retired as approved by the Georgia PSC in the 2011 IRP Update in order to comply with the State of Georgia's Multi-Pollutant Rule.

In the 2013 ARP, the Georgia PSC approved the amortization of the CWIP balances related to environmental projects that will not be completed at Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 over nine years beginning in January 2014 and the amortization of any remaining net book values of Plant Branch Unit 2 from October 2013 to December 2022, Plant Branch Unit 1 from May 2015 to December 2020, Plant Branch Unit 3 from May 2015 to December 2023, and Plant Branch Unit 4 from May 2015 to December 2024. The Georgia PSC deferred a decision regarding the appropriate recovery period for the costs associated with unusable materials and supplies remaining at the retiring plants to Georgia Power's next base rate case, which Georgia Power expects to file in 2016 (2016 Rate Case). In the 2013 IRP, the Georgia PSC also deferred decisions regarding the recovery of any fuel related costs that could be incurred in connection with the retirement units to be addressed in future fuel cases.

On July 1, 2014, the Georgia PSC approved Georgia Power's request to cancel the proposed biomass fuel conversion of Plant Mitchell Unit 3 (155 MWs) because it would not be cost effective for customers. Georgia Power expects to request decertification of Plant Mitchell Unit 3 in connection with the triennial Integrated Resource Plan to be filed in 2016. Georgia Power plans to continue to operate the unit as needed until the MATS rule becomes effective in April 2015.

The decertification of these units and fuel conversions are not expected to have a material impact on Southern Company's financial statements; however, the ultimate outcome depends on the Georgia PSC's order in the 2016 Rate Case and future fuel cases and cannot be determined at this time.

Fuel Cost Recovery

Georgia Power has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved a reduction in Georgia Power's total annual billings of approximately $567 million effective June 1, 2012, with an additional $122 million reduction effective January 1, 2013 through June 1, 2014. 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 or over recovered fuel balance exceeds $200 million. Georgia Power's fuel cost recovery includes costs associated with a natural gas hedging program as revised and approved by the Georgia PSC in February 2013, requiring it to use options and hedges within a 24-month time horizon. See Note 11 under "Energy-Related Derivatives" for additional information. On January 20, 2015, the Georgia PSC approved the deferral of Georgia Power's next fuel case filing until at least June 30, 2015.

Georgia Power's under recovered fuel balance totaled approximately $199 million at December 31, 2014 and is included in current assets and other deferred charges and assets. At December 31, 2013, Georgia Power's over recovered fuel balance totaled approximately $58 million and was included in current liabilities and 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

Georgia Power defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. Beginning January 1, 2014, Georgia Power is accruing $30 million annually under the 2013 ARP that is recoverable through base rates. As of December 31, 2014 and December 31, 2013, the balance in the regulatory asset related to storm damage was $98 million and $37 million, respectively, with approximately $30 million included in other regulatory assets, current for both years and approximately $68 million and $7 million included in other regulatory assets, deferred, respectively. Georgia Power expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs. As a result of the regulatory treatment, costs related to storms are generally 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 (collectively, Vogtle Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc., a subsidiary of The Shaw Group Inc., which was acquired by Chicago Bridge & Iron Company N.V. (CB&I) (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 that is 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. The Contractor's liability to the Vogtle Owners for schedule and performance liquidated damages and warranty claims is subject to a cap. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which have not 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%.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and CB&I's The Shaw Group Inc., respectively. 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. The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay certain termination costs. 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 2009, the NRC issued an Early Site Permit and Limited Work Authorization which allowed limited work to begin on Plant Vogtle Units 3 and 4. The NRC certified the Westinghouse Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, in late 2011, and issued combined construction and operating licenses (COLs) in early 2012. Receipt of the COLs allowed full construction to begin. 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 are expected as construction proceeds.

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 increases to the NCCR tariff of approximately $223 million, $35 million, $50 million, and $60 million, effective January 1, 2011, 2012, 2013, and 2014, respectively. On December 16, 2014, the Georgia PSC approved an increase to the NCCR tariff of approximately $27 million effective January 1, 2015.

In 2012, the Vogtle Owners and the Contractor began negotiations regarding the costs associated with design changes to the DCD and the delays in the timing of approval of the DCD and issuance of the COLs, including the assertion by the Contractor that the

Vogtle Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. Also in 2012, Georgia Power and the other Vogtle Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Vogtle Owners are not responsible for these costs. In 2012, the Contractor also filed suit against Georgia Power and the other Vogtle Owners in the U.S. District Court for the District of Columbia alleging the Vogtle Owners are responsible for these costs. In August 2013, the U.S. District Court for the District of Columbia dismissed the Contractor's suit, ruling that the proper venue is the U.S. District Court for the Southern District of Georgia. The Contractor appealed the decision to the U.S. Court of Appeals for the District of Columbia Circuit in September 2013. The portion of additional costs claimed by the Contractor in its initial complaint that would be attributable to Georgia Power (based on Georgia Power's ownership interest) is approximately $425 million (in 2008 dollars). The Contractor also asserted it is entitled to extensions of the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. On May 22, 2014, the Contractor filed an amended counterclaim to the suit pending in the U.S. District Court for the Southern District of Georgia alleging that (i) the design changes to the DCD imposed by the NRC delayed module production and the impacts to the Contractor are recoverable by the Contractor under the Vogtle 3 and 4 Agreement and (ii) the changes to the basemat rebar design required by the NRC caused additional costs and delays recoverable by the Contractor under the Vogtle 3 and 4 Agreement. The Contractor did not specify in its amended counterclaim the amounts relating to these new allegations; however, the Contractor has subsequently asserted related minimum damages (based on Georgia Power's ownership interest) of $113 million. The Contractor may from time to time continue to assert that it is entitled to additional payments with respect to these allegations, any of which could be substantial. Georgia Power has not agreed to the proposed cost or to any changes to the guaranteed substantial completion dates or that the Vogtle Owners have any responsibility for costs related to these issues. Litigation is ongoing and Georgia Power intends to vigorously defend the positions of the Vogtle Owners. Georgia Power also expects negotiations with the Contractor to continue with respect to cost and schedule during which negotiations the parties may reach a mutually acceptable compromise of their positions.

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. If the projected certified construction capital costs to be borne by Georgia Power increase by 5% or the projected in-service dates are significantly extended, Georgia Power is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. Georgia Power's eighth VCM report filed in February 2013 requested an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 from $4.4 billion to $4.8 billion and to extend the estimated in-service dates to the fourth quarter 2017 and the fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively.

In September 2013, the Georgia PSC approved a stipulation (2013 Stipulation) entered into by 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 accordance with the Georgia Integrated Resource Planning Act, any costs incurred by Georgia Power in excess of the certified amount will be included in rate base, provided Georgia Power shows the costs to be reasonable and prudent. In addition, financing costs on any construction-related costs in excess of the certified amount likely would be subject to recovery through AFUDC instead of the NCCR tariff.

The Georgia PSC has approved eleven VCM reports covering the periods through June 30, 2014, including construction capital costs incurred, which through that date totaled $2.8 billion.

On January 29, 2015, Georgia Power announced that it was notified by the Contractor of the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4, which would incrementally delay the previously disclosed estimated in-service dates by 18 months (from the fourth quarter of 2017 to the second quarter of 2019 for Unit 3 and from the fourth quarter of 2018 to the second quarter of 2020 for Unit 4). Georgia Power has not agreed to any changes to the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. Georgia Power does not believe that the Contractor's revised forecast reflects all efforts that may be possible to mitigate the Contractor's delay.

In addition, Georgia Power believes that, pursuant to the Vogtle 3 and 4 Agreement, the Contractor is responsible for the Contractor's costs related to the Contractor's delay (including any related construction and mitigation costs, which could be material) and that the Vogtle Owners are entitled to recover liquidated damages for the Contractor's delay beyond the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. Consistent with the Contractor's position in the pending litigation described above, Georgia Power expects the Contractor to contest any claims for liquidated damages and to assert that the Vogtle Owners are responsible for additional costs related to the Contractor's delay.

On February 27, 2015, Georgia Power filed its twelfth VCM report with the Georgia PSC covering the period from July 1 through December 31, 2014, which requests approval for an additional $0.2 billion of construction capital costs incurred during that period and reflects the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4 as well as additional estimated owner-related costs of approximately $10 million per month expected to result from the Contractor's proposed 18-month delay,

including property taxes, oversight costs, compliance costs, and other operational readiness costs. No Contractor costs related to the Contractor's proposed 18-month delay are included in the twelfth VCM report. Additionally, while Georgia Power has not agreed to any change to the guaranteed substantial completion dates, the twelfth VCM report includes a requested amendment to the Plant Vogtle Units 3 and 4 certificate to reflect the Contractor's revised forecast, to include the estimated owner's costs associated with the proposed 18-month Contractor delay, and to increase the estimated total in-service capital cost of Plant Vogtle Units 3 and 4 to $5.0 billion.

Georgia Power will continue to incur financing costs of approximately $30 million per month until Plant Vogtle Units 3 and 4 are placed in service. The twelfth VCM report estimates total associated financing costs during the construction period to be approximately $2.5 billion.

Processes are in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, 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 issues are expected to 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.

As construction continues, the risk remains that ongoing challenges with Contractor performance including additional challenges in its fabrication, assembly, delivery, and installation of the shield building and structural modules, delays in the receipt of the remaining permits necessary for the operation of Plant Vogtle Units 3 and 4, or other issues could arise and may further impact project schedule and cost. In addition, the IRS allocated production tax credits to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021.

Additional claims by the Contractor or Georgia Power (on behalf of the Vogtle Owners) are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement, but also may be resolved through litigation.

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

Gulf Power

Retail Base Rate Case

In December 2013, the Florida PSC voted to approve the Gulf Power Settlement Agreement among Gulf Power and all of the intervenors to the docketed proceeding with respect to Gulf Power's request to increase retail base rates. Under the terms of the Gulf Power Settlement Agreement, Gulf Power (1) increased base rates designed to produce an additional $35 million in annual revenues effective January 2014 and subsequently increased base rates designed to produce an additional $20 million in annual revenues effective January 2015; (2) continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); and (3) will accrue a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until Gulf Power's next base rate adjustment date or January 1, 2017, whichever comes first.

The Gulf Power Settlement Agreement also includes a self-executing adjustment mechanism that will increase the authorized ROE midpoint and range by 25 basis points in the event the 30-year treasury yield rate increases by an average of at least 75 basis points above 3.7947% for a consecutive six-month period.

The Gulf Power Settlement Agreement also provides that Gulf Power may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017. In any given month, such depreciation expense reduction may not exceed the amount necessary for the ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized ROE range then in effect. Recovery of the regulatory asset will occur over a period to be determined by the Florida PSC in Gulf Power's next base rate case or next depreciation and dismantlement study proceeding, whichever comes first. As a result, Gulf Power recognized an $8.4 million reduction in depreciation expense in 2014.

Pursuant to the Gulf Power Settlement Agreement, Gulf Power may not request an increase in its retail base rates to be effective until after June 2017, unless Gulf Power's actual retail ROE falls below the authorized ROE range.

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

Construction of Mississippi Power's Kemper IGCC is nearing completion and start-up activities will continue until the Kemper IGCC is placed in service. The Kemper IGCC will utilize an IGCC technology with an output capacity of 582 MWs. The Kemper IGCC will be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by Mississippi Power and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation in June 2013. In connection with the Kemper IGCC, Mississippi Power constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the planned 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 $245.3 million of grants awarded to the Kemper IGCC project by the DOE under the Clean Coal Power Initiative Round 2 (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 on natural gas on August 9, 2014 and continues to focus on completing the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, for which the in-service date is currently expected to occur in the first half of 2016.

Recovery of the Kemper IGCC 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) and costs subject to the cost cap remain subject to review and approval by the Mississippi PSC. Mississippi Power's Kemper IGCC 2010 project estimate, current cost estimate (which includes the impacts of the Mississippi Supreme Court's (Court) decision), and actual costs incurred as of December 31, 2014, as adjusted for the Court's decision, are as follows:

Cost Category	2010 Project Estimate[f]	Current Estimate	Actual Costs at 12/31/2014
		(in billions)	
Plant Subject to Cost Cap[a]	$ 2.40	$ 4.93	**$ 4.23**
Lignite Mine and Equipment	0.21	0.23	**0.23**
CO_2 Pipeline Facilities	0.14	0.11	**0.10**
AFUDC[b][c]	0.17	0.63	**0.45**
Combined Cycle and Related Assets Placed in Service – Incremental[d]	—	0.02	0.00
General Exceptions	0.05	0.10	**0.07**
Deferred Costs[c][e]	—	0.18	**0.12**
Total Kemper IGCC[a][c]	$ 2.97	$ 6.20	**$ 5.20**

(a) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, net of the DOE Grants and excluding the Cost Cap Exceptions. The Current Estimate and Actual Costs include non-incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service on August 9, 2014 that are subject to the $2.88 billion cost cap and excludes post-in-service costs for the lignite mine. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" for additional information.

(b) Mississippi Power's original estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC in 2012 as described in "Rate Recovery of Kemper IGCC Costs."

(c) Amounts in the Current Estimate reflect estimated costs through March 31, 2016.

(d) Incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service on August 9, 2014, net of costs related to energy sales. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" for additional information.

(e) The 2012 MPSC CPCN Order approved deferral of non-capital Kemper IGCC-related costs during construction as described in "Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities."

(f) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities which was approved in 2011 by the Mississippi PSC.

Of the total costs, including post-in-service costs for the lignite mine, incurred as of December 31, 2014, $3.04 billion was included in property, plant, and equipment (which is net of the DOE Grants and estimated probable losses of $2.05 billion), $1.8 million in other property and investments, $44.7 million in fossil fuel stock, $32.5 million in materials and supplies, $147.7 million in other regulatory assets, $11.6 million in other deferred charges and assets, and $23.6 million in AROs in the balance sheet, with $1.1 million previously expensed.

Mississippi Power does not intend to seek any rate recovery or joint owner contributions for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. Southern Company recorded pre-tax charges to income for revisions to the cost estimate of $868.0 million ($536.0 million after tax) and $1.2 billion ($729 million after tax) in 2014 and 2013, respectively. The increases to the cost estimate in 2014 primarily reflected costs related to extension of the project's schedule to ensure the required time for start-up activities and operational readiness, completion of construction, additional resources during start-up, and ongoing construction support during start-up and commissioning activities. The current estimate includes costs through March 31, 2016. Any further extension of the in-service date is currently estimated to result in additional base costs of approximately $25 million to $30 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. Any further extension of the in-service date with respect to the Kemper IGCC 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 $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees, which are being deferred as regulatory assets and are estimated to total approximately $7 million per month.

Any further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (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). In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the 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

The ultimate outcome of the rate recovery matters discussed herein, including the resolution of legal challenges, determinations of prudency, and the specific manner of recovery of prudently-incurred costs, cannot be determined at this time, but could have a material impact on the Company's results of operations, financial condition, and liquidity.

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 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 evaluation of the Rate Mitigation Plan (defined below) and other related proceedings during 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.

2013 Settlement Agreement

In January 2013, Mississippi Power entered into a settlement agreement with the Mississippi PSC that, among other things, established 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. The 2013 Settlement Agreement also allowed Mississippi Power to secure alternate financing for costs not otherwise recovered in any Mississippi PSC rate proceedings contemplated by the 2013 Settlement Agreement. The Court found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. See "2015 Mississippi Supreme Court Decision" below for additional information.

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 February 2013. Mississippi Power's intent under the 2013 Settlement Agreement was to securitize (1) prudently-incurred costs in excess of the certificated cost estimate and up to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, (2) accrued AFUDC, and (3) other prudently-incurred costs, which include carrying costs from the estimated in-service date until securitization is finalized and other costs not included in the Rate Mitigation Plan as approved by the Mississippi PSC.

The Court's decision did not impact Mississippi Power's ability to utilize alternate financing through securitization, the 2012 MPSC CPCN Order, or the February 2013 legislation. See "2015 Mississippi Supreme Court Decision" below for additional information.

2013 MPSC Rate Order

Consistent with the terms of the 2013 Settlement Agreement, in March 2013, the Mississippi PSC issued the 2013 MPSC 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. For the period from March 2013 through December 31, 2014, $257.2 million had been collected primarily to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service.

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 the in-service date. Mississippi Power will not

record AFUDC on any additional costs of the Kemper IGCC that exceed the $2.88 billion cost cap, except for Cost Cap Exception amounts. Mississippi Power will continue to record AFUDC and collect and defer the approved rates through the in-service date until directed to do otherwise by the Mississippi PSC.

On August 18, 2014, Mississippi Power provided an analysis of the costs and benefits of placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service, including the expected accounting treatment. Mississippi Power's analysis requested, among other things, confirmation of Mississippi Power's accounting treatment by the Mississippi PSC of the continued collection of rates as prescribed by the 2013 MPSC Rate Order, with the current recognition as revenue of the related equity return on all assets placed in service and the deferral of all remaining rate collections under the 2013 MPSC Rate Order to a regulatory liability account. See "2015 Mississippi Supreme Court Decision" for additional information regarding the decision of the Court which would discontinue the collection of, and require the refund of, all amounts previously collected under the 2013 MPSC Rate Order.

In addition, Mississippi Power's August 18, 2014 filing with the Mississippi PSC requested confirmation of Mississippi Power's accounting treatment by the Mississippi PSC of the continued accrual of AFUDC through the in-service date of the remainder of the Kemper IGCC and the deferral of operating costs for the combined cycle as regulatory assets. Under Mississippi Power's proposal, non-incremental costs that would have been incurred whether or not the combined cycle was placed in service would be included in a regulatory asset and would continue to be subject to the $2.88 billion cost cap. Additionally, incremental costs that would not have been incurred if the combined cycle had not gone into service would be included in a regulatory asset and would not be subject to the cost cap because these costs are incurred to support operation of the combined cycle. All energy revenues associated with the combined cycle variable operating and maintenance expenses would be credited to this regulatory asset. See "Regulatory Assets and Liabilities" for additional information. Any action by the Mississippi PSC that is inconsistent with the treatment requested by Mississippi Power could have a material impact on the results of operations, financial condition, and liquidity of Southern Company.

2015 Mississippi Supreme Court Decision

On February 12, 2015, the Court issued its decision in the legal challenge to the 2013 MPSC Rate Order filed by Thomas A. Blanton. 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. The Court's ruling remands the matter to the Mississippi PSC to (1) fix by order the rates that were in existence prior to the 2013 MPSC Rate Order, (2) fix no rate increases until the Mississippi PSC is in compliance with the Court's ruling, and (3) enter an order refunding amounts collected under the 2013 MPSC Rate Order. Through December 31, 2014, Mississippi Power had collected $257.2 million through rates under the 2013 MPSC Rate Order. Any required refunds would also include carrying costs. The Court's decision will become legally effective upon the issuance of a mandate to the Mississippi PSC. Absent specific instruction from the Court, the Mississippi PSC will determine the method and timing of the refund. Mississippi Power is reviewing the Court's decision and expects to file a motion for rehearing which would stay the Court's mandate until either the case is reheard and decided or seven days after the Court issues its order denying Mississippi Power's request for rehearing. Mississippi Power is also evaluating its regulatory options.

Rate Mitigation Plan

In March 2013, Mississippi Power, in compliance with the 2013 MPSC Rate Order, filed a revision to the proposed rate recovery plan with the Mississippi PSC for the Kemper IGCC for cost recovery through 2020 (Rate Mitigation Plan), which is still under review by the Mississippi PSC. The revenue requirements set forth in the Rate Mitigation Plan assume the sale of a 15% undivided interest in the Kemper IGCC to SMEPA and utilization of bonus depreciation, which currently requires that the related long-term asset be placed in service in 2015. In the Rate Mitigation Plan, Mississippi Power proposed recovery of an annual revenue requirement of approximately $156 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. The 2013 MPSC Rate Order, which increased rates beginning in March 2013, was integral to the Rate Mitigation Plan, which contemplates amortization of the regulatory liability balance at the in-service date to be used to mitigate customer rate impacts through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the Rate Mitigation Plan, Mississippi Power proposed annual rate recovery to remain the same from 2014 through 2020, with the proposed revenue requirement approximating the forecasted cost of service for the period 2014 through 2020. Under Mississippi Power's proposal, to the extent the actual annual cost of service differs from the approved forecast for certain items, the difference would be deferred as a regulatory asset or liability, subject to accrual of carrying costs, and would be included in the next year's rate recovery calculation. If any deferred balance remains at the end of 2020, the

Mississippi PSC would review the amount and, if approved, determine the appropriate method and period of disposition. See "Regulatory Assets and Liabilities" for additional information.

To the extent that refunds of amounts collected under the 2013 MPSC Rate Order are required on a schedule different from the amortization schedule proposed in the Rate Mitigation Plan, the customer billing impacts proposed under the Rate Mitigation Plan would no longer be viable. See "2015 Mississippi Supreme Court Decision" above for additional information.

In the event that the Mirror CWIP regulatory liability is refunded to customers prior to the in-service date of the Kemper IGCC and is, therefore, not available to mitigate rate impacts under the Rate Mitigation Plan, the Mississippi PSC does not approve a refund schedule that facilitates rate mitigation, or Mississippi Power withdraws the Rate Mitigation Plan, Mississippi Power would seek rate recovery through alternate means, which could include a traditional rate case.

In addition to current estimated costs at December 31, 2014 of $6.2 billion, Mississippi Power anticipates that it will incur additional costs after the Kemper IGCC in-service date until the Kemper IGCC cost recovery approach is finalized. These costs include, but are not limited to, regulatory costs and additional carrying costs which could be material. Recovery of these costs would be subject to approval by the Mississippi PSC.

Prudence Reviews

The Mississippi PSC's review of Kemper IGCC costs is ongoing. On August 5, 2014, the Mississippi PSC ordered that a consolidated prudence determination of all Kemper IGCC costs be completed after the entire project has been placed in service and has demonstrated availability for a reasonable period of time as determined by the Mississippi PSC and the MPUS. The Mississippi PSC has encouraged the parties to work in good faith to settle contested issues and Mississippi Power is working to reach a mutually acceptable resolution. As a result of the Court's decision, Mississippi Power intends to request that the Mississippi PSC reconsider its prudence review schedule. See "2015 Mississippi Supreme Court Decision" 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.

On August 18, 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. As of December 31, 2014, the regulatory asset balance associated with the Kemper IGCC was $147.7 million. The projected balance at March 31, 2016 is estimated to total approximately $269.8 million. The amortization period of 40 years proposed by Mississippi Power for any such costs approved for recovery remains subject to approval by the Mississippi PSC.

The 2013 MPSC Rate Order approved 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. On February 12, 2015, the Court ordered the Mississippi PSC to refund Mirror CWIP and to fix by order the rates that were in existence prior to the 2013 MPSC Rate Order. Mississippi Power is deferring the collections under the approved rates in the Mirror CWIP regulatory liability until otherwise directed by the Mississippi PSC. Mississippi Power is also accruing carrying costs on the unamortized balance of the Mirror CWIP regulatory liability for the benefit of retail customers. As of December 31, 2014, the balance of the Mirror CWIP regulatory liability, including carrying costs, was $270.8 million.

See "2015 Mississippi Supreme Court Decision" for additional information.

See Note 1 under "Regulatory Assets and Liabilities" for additional information.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, Mississippi Power will own 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 has entered into agreements with Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tengrys, LLC, pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC. The agreements with Denbury and Treetop provide termination rights in the event that Mississippi Power does not satisfy its contractual obligation with respect to deliveries of captured CO_2 by May 11, 2015. While Mississippi Power has received no indication from either Denbury or Treetop of their intent to terminate their respective agreements, any termination could result in a material reduction in future chemical product sales revenues but is not expected to have a material financial impact on Southern Company to the extent Mississippi Power is not able to enter into other similar contractual arrangements.

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

Proposed Sale of Undivided Interest to SMEPA

In 2010, Mississippi Power and SMEPA entered into an APA whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. In 2012, the Mississippi PSC approved the sale and transfer of the 17.5% undivided interest in the Kemper IGCC to SMEPA. Later in 2012, Mississippi Power and SMEPA signed an amendment to the APA whereby SMEPA reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC. In March 2013, Mississippi Power and SMEPA signed an amendment to the APA whereby Mississippi Power and SMEPA agreed to amend the power supply agreement entered into by the parties in 2011 to reduce the capacity amounts to be received by SMEPA by half (approximately 75 MWs) at the sale and transfer of the undivided interest in the Kemper IGCC to SMEPA. Capacity revenues under the 2011 power supply agreement were $16.7 million in 2014. In December 2013, Mississippi Power and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2014.

By letter agreement dated October 6, 2014, Mississippi Power and SMEPA agreed in principle on certain issues related to SMEPA's proposed purchase of a 15% undivided interest in the Kemper IGCC. The letter agreement contemplated certain amendments to the APA, which the parties anticipated to be incorporated into the APA on or before December 31, 2014. The parties agreed to further amend the APA as follows: (1) Mississippi Power agreed to cap at $2.88 billion the portion of the purchase price payable for development and construction costs, net of the Cost Cap Exceptions, title insurance reimbursement, and AFUDC and/or carrying costs through the Closing Commitment Date (defined below); (2) SMEPA agreed to close the purchase within 180 days after the date of the execution of the amended APA or before the Kemper IGCC in-service date, whichever occurs first (Closing Commitment Date), subject only to satisfaction of certain conditions; and (3) AFUDC and/or carrying costs will continue to be accrued on the capped development and construction costs, the Cost Cap Exceptions, and any operating costs, net of revenues until the amended APA is executed by both parties, and thereafter AFUDC and/or carrying costs and payment of interest on SMEPA's deposited money will be suspended and waived provided closing occurs by the Closing Commitment Date. The letter agreement also provided for certain post-closing adjustments to address any differences between the actual and the estimated amounts of post-in-service date costs (both expenses and capital) and revenue credits for those portions of the Kemper IGCC previously placed in service.

By letter dated December 18, 2014, SMEPA notified Mississippi Power that SMEPA decided not to extend the estimated closing date in the APA or revise the APA to include the contemplated amendments; however, both parties agree that the APA will remain in effect until closing or until either party gives notice of termination.

The closing of this transaction is also conditioned upon execution of a joint ownership and operating agreement, the absence of material adverse effects, receipt of all construction permits, and appropriate regulatory approvals, as well as SMEPA's receipt of Rural Utilities Service (RUS) funding. In 2012, SMEPA received a conditional loan commitment from RUS for the purchase.

In 2012, on January 2, 2014, and on October 9, 2014, Mississippi Power received $150 million, $75 million, and $50 million, respectively, of interest-bearing refundable deposits from SMEPA to be applied to the purchase. While the expectation is that these amounts will be applied to the purchase price at closing, Mississippi Power would be required to refund the deposits upon the termination of the APA or within 15 days of a request by SMEPA for a full or partial refund. Given the interest-bearing nature of the deposits and SMEPA's ability to request a refund, the deposits have been presented as a current liability in the balance sheet and as financing proceeds in the statement of cash flow. In July 2013, Southern Company entered into an agreement with SMEPA

under which Southern Company has agreed to guarantee the obligations of Mississippi Power with respect to any required refund of the deposits.

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. In the 2015 Mississippi Supreme Court decision, the Court declined to rule on the constitutionality of the Baseload Act. See "Rate Recovery of Kemper IGCC Costs" herein for additional information.

Investment Tax Credits and Bonus Depreciation

The IRS allocated $279.0 million (Phase II) of Internal Revenue Code Section 48A tax credits to Mississippi Power in connection with the Kemper IGCC. Through December 31, 2014, Mississippi Power had recorded tax benefits totaling $276.4 million for the Phase II credits, of which approximately $210.0 million had been utilized through that date. These credits will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC and are dependent upon meeting the IRS certification requirements, including an in-service date no later than April 19, 2016 and 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. Mississippi Power currently expects to place the Kemper IGCC in service in the first half of 2016. In addition, a portion of the Phase II tax credits will be subject to recapture upon completion of SMEPA's proposed purchase of an undivided interest in the Kemper IGCC as described above.

On December 19, 2014, the Tax Increase Prevention Act of 2014 (TIPA) was signed into law. The TIPA retroactively extended several tax credits through 2014 and extended 50% bonus depreciation for property placed in service in 2014 (and for certain long-term production-period projects to be placed in service in 2015). The extension of 50% bonus depreciation had a positive impact on Southern Company's cash flows and, combined with bonus depreciation allowed in 2014 under the ATRA, resulted in approximately $130 million of positive cash flows related to the combined cycle and associated common facilities portion of the Kemper IGCC for the 2014 tax year. The estimated cash flow benefit of bonus depreciation related to TIPA is expected to be approximately $45 million to $50 million for the 2015 tax year. See "Rate Recovery of Kemper IGCC Costs – Rate Mitigation Plan" herein for additional information.

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

Section 174 Research and Experimental Deduction

Southern Company reduced tax payments for 2014 and included in its 2013 consolidated federal income tax return deductions for research and experimental (R&E) expenditures related to the Kemper IGCC. Due to the uncertainty related to this tax position, Southern Company recorded an unrecognized tax benefit of approximately $160 million as of December 31, 2014. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Other Matters

Sierra Club Settlement Agreement

On August 1, 2014, Mississippi Power entered into the Sierra Club Settlement Agreement that, among other things, requires the Sierra Club to dismiss or withdraw all pending legal and regulatory challenges of the Kemper IGCC and the flue gas desulfurization system (scrubber) project at Plant Daniel Units 1 and 2. In addition, the Sierra Club agreed to refrain from initiating, intervening in, and/or challenging certain legal and regulatory proceedings for the Kemper IGCC, including, but not limited to, the prudence review, and Plant Daniel for a period of three years from the date of the Sierra Club Settlement Agreement. On August 4, 2014, the Sierra Club filed all of the required motions necessary to dismiss or withdraw all appeals associated with certification of the Kemper IGCC and the Plant Daniel Units 1 and 2 scrubber project, which the applicable courts subsequently granted.

Under the Sierra Club Settlement Agreement, Mississippi Power agreed to, among other things, fund a $15 million grant payable over a 15-year period for an energy efficiency and renewable program and contribute $2 million to a conservation fund. In accordance with the Sierra Club Settlement Agreement, Mississippi Power paid $7 million in 2014, recognized in other income (expense), net in Southern Company's statement of income. 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. Mississippi Power 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, and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) and begin operating those units solely on natural gas no later than April 2016.

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 and with Duke Energy Florida, Inc. for a combustion turbine unit at Intercession City, Florida. 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, 2014, 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%	$ 3,420	$ 2,059	$ 46
Plant Hatch (nuclear)	50.1	1,117	559	66
Plant Miller (coal) Units 1 and 2	91.8	1,512	561	14
Plant Scherer (coal) Units 1 and 2	8.4	254	83	1
Plant Wansley (coal)	53.5	856	278	15
Rocky Mountain (pumped storage)	25.4	182	124	2
Intercession City (combustion turbine)	33.3	14	5	—
Plant Stanton (combined cycle) Unit A	65.0	157	47	—

Georgia Power also owns 45.7% of Plant Vogtle Units 3 and 4 that are currently under construction. See Note 3 under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" for additional information.

Alabama Power, Georgia Power, and Southern Power have contracted to operate and maintain the jointly-owned facilities, except for Rocky Mountain and Intercession City, as agents for their respective co-owners. 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.

5. INCOME TAXES

Southern Company files a consolidated federal income tax return, combined state income tax returns for the States of Alabama, Georgia, and Mississippi, and unitary income tax returns for the States of California, North Carolina, and Texas. 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:

	2014	2013	2012
		(in millions)	
Federal —			
Current	**$ 175**	$ 363	$ 177
Deferred	**695**	386	1,011
	870	749	1,188
State —			
Current	**93**	(10)	61
Deferred	**14**	110	85
	107	100	146
Total	**$ 977**	$ 849	$ 1,334

Net cash payments for income taxes in 2014, 2013, and 2012 were $272 million, $139 million, and $38 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:

	2014	2013
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	$ 11,125	$ 9,710
Property basis differences	1,332	1,515
Leveraged lease basis differences	299	287
Employee benefit obligations	613	491
Premium on reacquired debt	103	113
Regulatory assets associated with employee benefit obligations	1,390	705
Regulatory assets associated with AROs	871	824
Other	523	350
Total	16,256	13,995
Deferred tax assets —		
Federal effect of state deferred taxes	430	421
Employee benefit obligations	1,675	1,048
Over recovered fuel clause	—	30
Other property basis differences	453	157
Deferred costs	86	84
ITC carryforward	480	121
Unbilled revenue	67	116
Other comprehensive losses	89	54
AROs	871	824
Estimated Loss on Kemper IGCC	631	472
Deferred state tax assets	117	77
Other	342	220
Total	5,241	3,624
Valuation allowance	(49)	(49)
Total deferred tax assets	5,192	3,575
Total deferred tax liabilities, net	11,064	10,420
Portion included in current assets/(liabilities), net	504	143
Accumulated deferred income taxes	$ 11,568	$ 10,563

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

At December 31, 2014, Southern Company had subsidiaries with State of Georgia net operating loss (NOL) carryforwards totaling $701 million, which could result in net state income tax benefits of $41 million, if utilized. However, the subsidiaries have established a valuation allowance for the entire amount due to the remote likelihood that the tax benefit will be realized. These NOLs expire between 2018 and 2021. Beginning in 2002, the State of Georgia allowed Southern Company to file a combined return, which has prevented the creation of any additional NOL carryforwards.

At December 31, 2014, the tax-related regulatory assets to be recovered from customers were $1.5 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, 2014, the tax-related regulatory liabilities to be credited to customers were $192 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 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 2014, $16 million in 2013, and $23 million in 2012. At December 31, 2014, Southern Company had a federal ITC carryforward which is expected to result in $379 million of federal income tax benefit. The ITC carryforward expires in 2023, but is expected to be utilized in 2015. Additionally, Southern Company had state ITC carryforwards for the states of Georgia and Mississippi totaling $159 million, which will expire between 2020 and 2024.

Effective Tax Rate

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

	2014	2013	2012
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.3**	2.5	2.5
Employee stock plans dividend deduction	**(1.4)**	(1.6)	(1.0)
Non-deductible book depreciation	**1.4**	1.5	0.9
AFUDC-Equity	**(2.9)**	(2.6)	(1.3)
ITC basis difference	**(1.6)**	(1.2)	(0.3)
Other	**(0.3)**	(0.5)	(0.2)
Effective income tax rate	**32.5%**	33.1%	35.6%

Southern Company's effective tax rate is typically lower than the statutory rate due to its employee stock plans' dividend deduction and non-taxable AFUDC equity. The 2014 effective tax rate decrease, as compared to 2013, is primarily due to an increase in non-taxable AFUDC equity and an increase in tax benefits related to federal ITCs. Additionally, the 2013 effective rate decrease, as compared to 2012, is primarily due to an increase in non-taxable AFUDC equity.

Unrecognized Tax Benefits

Changes during the year in unrecognized tax benefits were as follows:

	2014	2013	2012
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 7**	$ 70	$ 120
Tax positions increase from current periods	**64**	3	13
Tax positions increase from prior periods	**102**	—	7
Tax positions decrease from prior periods	**(3)**	(66)	(56)
Reductions due to settlements	**—**	—	(10)
Reductions due to expired statute of limitations	**—**	—	(4)
Balance at end of year	**$ 170**	$ 7	$ 70

The tax positions increase from current periods and increase from prior periods for 2014 relate primarily to a deduction for R&E expenditures related to the Kemper IGCC. See Note 3 under "Integrated Coal Gasification Combined Cycle – Section 174 Research and Experimental Deduction" for more information. The tax positions decrease from prior periods for 2013 relate primarily to the tax accounting method change for repairs related to generation assets. See "Tax Method of Accounting for Repairs" herein for additional information.

The impact on Southern Company's effective tax rate, if recognized, is as follows:

	2014	2013	2012
		(in millions)	
Tax positions impacting the effective tax rate	**$ 10**	$ 7	$ 5
Tax positions not impacting the effective tax rate	**160**	—	65
Balance of unrecognized tax benefits	**$ 170**	$ 7	$ 70

The tax positions impacting the effective tax rate for 2014, 2013, and 2012 relate to federal and state income tax credits. The tax positions not impacting the effective tax rate for 2014 relate to a deduction for R&E expenditures related to the Kemper IGCC. The tax positions not impacting the effective tax rate for 2012 relate to the tax accounting method change for repairs related to generation assets. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Southern Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial for all periods presented. 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 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 federal income tax return and has received a partial acceptance letter from the IRS; however, the IRS has not finalized its audit. 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 2008.

Tax Method of Accounting for Repairs

In 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. Additionally, in April 2013, the IRS issued Revenue Procedure 2013-24, which provides guidance for taxpayers related to the deductibility of repair costs associated with generation assets. Based on a review of the regulations, Southern Company incorporated provisions related to repair costs for generation assets into its consolidated 2012 federal income tax return and reversed all related unrecognized tax positions. In September 2013, the IRS issued Treasury Decision 9636, "Guidance Regarding Deduction and Capitalization of Expenditures Related to Tangible Property," which are final tangible property regulations applicable to taxable years beginning on or after January 1, 2014. Southern Company continues to review this guidance; however, these regulations are not expected to have a material impact on the Company's financial statements.

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, 2014 and 2013, 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 each of December 31, 2014 and 2013, 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:

	2014	2013
	(in millions)	
Senior notes	$ 2,375	$ 428
Other long-term debt	775	12
Pollution control revenue bonds	152	—
Capitalized leases	31	29
Total	$ 3,333	$ 469

Maturities through 2019 applicable to total long-term debt are as follows: $3.33 billion in 2015; $1.83 billion in 2016; $1.55 billion in 2017; $862 million in 2018; and $1.21 billion in 2019.

Subsequent to December 31, 2014, Alabama Power announced the redemption of $250 million aggregate principal amount of its Series DD 5.65% Senior Notes due March 15, 2035 that will occur on March 16, 2015.

Bank Term Loans

Southern Company and certain of the traditional operating companies have entered into various floating rate bank term loan agreements for loans bearing interest based on one-month LIBOR. At December 31, 2014, Mississippi Power had outstanding bank term loans totaling $775 million, which are reflected in the statements of capitalization as long-term debt. At December 31, 2013, Mississippi Power had outstanding bank term loans totaling $525 million and Georgia Power had outstanding bank term loans totaling $400 million.

In January 2014, Mississippi Power entered into an 18-month floating rate bank loan bearing interest based on one-month LIBOR. The term loan was for $250 million aggregate principal amount and the proceeds were used for working capital and other general corporate purposes, including Mississippi Power's continuous construction program.

In February 2014, Georgia Power repaid three four-month floating rate bank loans in an aggregate principal amount of $400 million.

In June 2014, Southern Company entered into a 90-day floating rate bank loan bearing interest based on one-month LIBOR. This short-term loan was for $250 million aggregate principal amount and the proceeds were used for working capital and other general corporate purposes, including the investment by Southern Company in its subsidiaries. This bank loan was repaid in August 2014.

The outstanding bank loans as of December 31, 2014, all of which relate to Mississippi Power, have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, 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, 2014, Mississippi Power 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) on February 20, 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 will 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 Title XVII Loan Guarantee Program (Eligible Project Costs). Aggregate borrowings under the FFB Credit Facility may not exceed the lesser of (i) 70% of Eligible Project Costs or (ii) approximately $3.46 billion.

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

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

On February 20, 2014, Georgia Power made initial borrowings under the FFB Credit Facility in an aggregate principal amount of $1.0 billion. The interest rate applicable to $500 million of the initial advance under the FFB Credit Facility is 3.860% for an interest period that extends to 2044 and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to 2029, and is expected to be reset from time to time thereafter through 2044. In connection with its entry into the agreements with the DOE and the FFB, Georgia Power incurred issuance costs of approximately $66 million, which will be amortized over the life of the borrowings under the FFB Credit Facility.

On December 11, 2014, Georgia Power made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $200 million. The interest rate applicable to the $200 million advance in December 2014 under the FFB Credit Facility is 3.002% for an interest period that extends to 2044.

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, compliance with the Cargo Preference Act of 1954, 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). 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 $1.4 billion of senior notes in 2014. Southern Company issued $750 million and its subsidiaries issued a total of $600 million. The proceeds of these 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.

At December 31, 2014 and 2013, Southern Company and its subsidiaries had a total of $18.2 billion and $17.3 billion, respectively, of senior notes outstanding. At December 31, 2014 and 2013, Southern Company had a total of $2.2 billion and $1.8 billion, respectively, of senior notes outstanding.

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.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the traditional 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 obligations represent obligations under installment sales agreements with respect to facilities constructed with the proceeds of pollution control bonds issued by public authorities. The traditional operating companies had $3.2 billion of outstanding pollution control revenue bonds at December 31, 2014 and 2013. The traditional 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.

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.

In November 2013, the MBFC entered into an agreement to issue up to $33.75 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2013A (Mississippi Power Company Project) and up to $11.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2013B (Mississippi Power Company Project) for the benefit of Mississippi Power. In May 2014 and August 2014, the MBFC issued $12.3 million and $10.5 million, respectively, aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013A for the benefit of Mississippi Power and proceeds were used to reimburse Mississippi Power for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility related to the Kemper IGCC. In December 2014, the MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013A of $22.87 million and Series 2013B of $11.25 million were paid at maturity.

Mississippi Power had $50 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2014 and 2013. Mississippi Power had no obligation at December 31, 2014 and $11.3 million of such obligations related to taxable revenue bonds outstanding at December 31, 2013. Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.

Mississippi Power's agreements relating to its taxable revenue bonds include covenants limiting debt levels consistent with those described above under "Bank Term Loans."

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.

In September 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, 2014 of approximately $80 million with an annual interest rate of 4.9%. Amortization of the capital lease asset for the air separation unit will begin when the Kemper IGCC is placed in service.

At December 31, 2014 and 2013, the capitalized lease obligations for Georgia Power's corporate headquarters building were $40 million and $45 million, respectively, with an annual interest rate of 7.9% for both years.

At December 31, 2014 and 2013, Alabama Power had a capitalized lease obligation of $5 million for a natural gas pipeline with an annual interest rate of 6.9%.

At December 31, 2014 and 2013, a subsidiary of Southern Company had capital lease obligations of approximately $34 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 3.2%.

Other Obligations

In 2012, January 2014, and October 2014, Mississippi Power received $150 million, $75 million, and $50 million, respectively, interest-bearing refundable deposits from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the sale is closed, the deposits bear interest at Mississippi Power's AFUDC rate adjusted for income taxes, which was 10.134% per annum for 2014, 9.932% per annum for 2013, and 9.967% per annum for 2012, and are refundable to SMEPA upon termination of the APA related to such purchase or within 15 days of a request by SMEPA for a full or partial refund. In July 2013, Southern Company entered into an agreement with SMEPA under which Southern Company has agreed to guarantee the obligations of Mississippi Power with respect to any required refund of the deposits.

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 outstanding principal amount of $41 million as of December 31, 2014.

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.

Bank Credit Arrangements

At December 31, 2014, committed credit arrangements with banks were as follows:

	Expires						Executable Term Loans		Due Within One Year	
Company	2015	2016	2017	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
	(in millions)				(in millions)		(in millions)		(in millions)	
Southern Company	$ —	$ —	$ —	$1,000	$1,000	$ 1,000	$ —	$ —	$ —	$ —
Alabama Power	228	50	—	1,030	1,308	1,308	58	—	58	170
Georgia Power	—	150	—	1,600	1,750	1,736	—	—	—	—
Gulf Power	80	165	30	—	275	275	50	—	50	30
Mississippi Power	135	165	—	—	300	300	25	40	65	70
Southern Power	—	—	—	500	500	488	—	—	—	—
Other	70	—	—	—	70	70	20	—	20	50
Total	$ 513	$ 530	$ 30	$4,130	$5,203	$ 5,177	$ 153	$ 40	$ 193	$ 320

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 operating companies, and Southern Power. Compensating balances are not legally restricted from withdrawal.

Subject to applicable market conditions, Southern Company and its subsidiaries expect to renew their bank credit arrangements as needed, prior to expiration.

Most of these 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 Mississippi Power, any securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2014, Southern Company, the traditional operating companies, and Southern Power were each in compliance with their respective debt limit covenants.

A portion of the $5.2 billion unused credit with banks is allocated to provide liquidity support to the traditional operating companies' variable rate pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014 was approximately $1.8 billion. In addition, at December 31, 2014, the traditional operating companies had $476 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months. As of December 31, 2014, $98 million of certain pollution control revenue bonds of Georgia Power were reclassified to securities due within one year in anticipation of their redemption in connection with unit retirement decisions. See Note 3 under "Retail Regulatory Matters – Georgia Power – Integrated Resource Plans" for additional information.

Southern Company, the traditional operating companies, and Southern Power make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. Southern Company, the traditional operating companies, and Southern Power may also borrow through various other arrangements with banks. 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, 2014:		
Commercial paper	**$ 803**	**0.3%**
Short-term bank debt	**—**	**—%**
Total	**$ 803**	**0.3%**
December 31, 2013:		
Commercial paper	$ 1,082	0.2%
Short-term bank debt	400	0.9%
Total	$ 1,482	0.4%

Redeemable Preferred Stock of Subsidiaries

Each of the traditional 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 "noncontrolling interest," a separate component of "Stockholders' Equity," on Southern Company's balance sheets, statements of capitalization, and statements of stockholders' equity.

There were no changes for the years ended December 31, 2014 and 2013 in redeemable preferred stock of subsidiaries for Southern Company.

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 2014, 2013, and 2012, the traditional operating companies and Southern Power incurred fuel expense of $6.0 billion, $5.5 billion, and $5.1 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 $198 million, $157 million, and $171 million for 2014, 2013, and 2012, respectively.

Estimated total obligations under these commitments at December 31, 2014 were as follows:

	Operating Leases [1]	Other
	(in millions)	
2015	$ 230	$ 11
2016	234	11
2017	264	10
2018	270	7
2019	274	6
2020 and thereafter	1,980	50
Total	$ 3,252	$ 95

(1) A total of $1.1 billion of biomass PPAs included under operating leases is contingent upon the counterparties meeting specified contract dates for commercial operation and may change as a result of regulatory action.

Operating Leases

The Southern Company system has operating lease agreements with various terms and expiration dates. Total rent expense was $118 million, $123 million, and $155 million for 2014, 2013, and 2012, 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, 2014, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
		(in millions)	
2015	$ 50	$ 50	$ 100
2016	41	48	89
2017	18	47	65
2018	9	35	44
2019	6	23	29
2020 and thereafter	20	228	248
Total	$ 144	$ 431	$ 575

For the traditional 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 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 $53 million. At the termination of the leases, the lessee may renew the lease or 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 December 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 2017. 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

During 2014, Southern Company issued approximately 20.8 million shares of common stock (including approximately 5.0 million treasury shares) for approximately $806 million through the employee and director stock plans and the Southern Investment Plan. The Company may satisfy its obligations with respect to the plans in several ways, including through using newly issued shares or treasury shares or acquiring shares on the open market through the independent plan administrators.

From August 2013 through December 2014, Southern Company used shares held in treasury, to the extent available, and newly issued shares to satisfy the requirements under the Southern Investment Plan and the employee savings plan. Beginning in January 2015, Southern Company ceased issuing additional shares under the Southern Investment Plan and the employee savings plan. All sales under these plans are now being funded with shares acquired on the open market by the independent plan administrators.

Beginning in 2015, Southern Company expects to repurchase shares of common stock to offset all or a portion of the incremental shares issued under its employee and director stock plans, including through stock option exercises. The Southern Company Board of Directors has approved the repurchase of up to 20 million shares of common stock for such purpose until December 31, 2017. Repurchases may be made by means of open market purchases, privately negotiated transactions, or accelerated or other share repurchase programs, in accordance with applicable securities laws.

Shares Reserved

At December 31, 2014, a total of 93 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 shares units as discussed below). Of the total 93 million shares reserved, there were 15 million shares of common stock remaining available for awards under the Omnibus Incentive Compensation Plan as of December 31, 2014.

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of Southern Company system employees ranging from line management to executives. As of December 31, 2014, there were 5,437 current and former employees participating in the stock option program. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. Southern Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. Stock options held by employees of a company undergoing a change in control vest upon the change in control.

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	2013	2012
Expected volatility	**14.6%**	16.6%	17.7%
Expected term *(in years)*	**5**	5	5
Interest rate	**1.5%**	0.9%	0.9%
Dividend yield	**4.9%**	4.4%	4.2%
Weighted average grant-date fair value	**$2.20**	$2.93	$3.39

Southern Company's activity in the stock option program for 2014 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2013	38,819,366	$38.64
Granted	12,812,691	41.40
Exercised	11,585,363	35.06
Cancelled	117,375	42.72
Outstanding at December 31, 2014	**39,929,319**	**$40.55**
Exercisable at December 31, 2014	**20,695,310**	**$38.76**

The number of stock options vested, and expected to vest in the future, as of December 31, 2014 was not significantly different from the number of stock options outstanding at December 31, 2014 as stated above. As of December 31, 2014, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately seven years and six years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $342 million and $214 million, respectively.

As of December 31, 2014, there was $10 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 16 months.

For the years ended December 31, 2014, 2013, and 2012, total compensation cost for stock option awards recognized in income was $27 million, $25 million, and $23 million, respectively, with the related tax benefit also recognized in income of $10 million, $10 million, and $9 million, respectively.

The total intrinsic value of options exercised during the years ended December 31, 2014, 2013, and 2012 was $125 million, $77 million, and $162 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $48 million, $30 million, and $62 million for the years ended December 31, 2014, 2013, and 2012, respectively.

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, 2014, 2013, and 2012 was $400 million, $204 million, and $397 million, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of Southern Company system employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount. Performance share units held by employees of a company undergoing a change in control vest upon the change in control.

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's 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. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. 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 award units.

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	2014	2013	2012
Expected volatility	**12.6%**	12.0%	16.0%
Expected term *(in years)*	**3**	3	3
Interest rate	**0.6%**	0.4%	0.4%
Annualized dividend rate	**$2.03**	$1.96	$1.89
Weighted average grant-date fair value	**$37.54**	$40.50	$41.99

Total unvested performance share units outstanding as of December 31, 2013 were 1,643,759. During 2014, 1,057,813 performance share units were granted, 755,716 performance share units were vested, and 115,475 performance share units were forfeited, resulting in 1,830,381 unvested units outstanding at December 31, 2014. In January 2015, the vested performance share award units were converted into 105,783 shares outstanding at a share price of $49.71 for the three-year performance and vesting period ended December 31, 2014.

For the years ended December 31, 2014, 2013, and 2012, total compensation cost for performance share units recognized in income was $33 million, $31 million, and $28 million, respectively, with the related tax benefit also recognized in income of $13 million, $12 million, and $11 million, respectively. As of December 31, 2014, there was $37 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 20 months.

Diluted Earnings Per Share

For Southern Company, the only difference in computing basic and diluted earnings per share is attributable to awards outstanding under the stock option and performance share plans. The effect of both stock options and performance share award units were determined using the treasury stock method. Shares used to compute diluted earnings per share were as follows:

	Average Common Stock Shares		
	2014	2013	2012
		(in millions)	
As reported shares	**897**	877	871
Effect of options and performance share award units	**4**	4	8
Diluted shares	**901**	881	879

Stock options and performance share award units that were not included in the diluted earnings per share calculation because they were anti-dilutive were $7 million and $16 million as of December 31, 2014 and 2013, respectively.

Common Stock Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2014, consolidated retained earnings included $6.4 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 $13.6 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 herein 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. On April 1, 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 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 current maximum annual assessments for Alabama Power and Georgia Power under the NEIL policies would be $50 million and $72 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 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.

As of December 31, 2014, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2014:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 13	$ —	$ 13
Interest rate derivatives	—	8	—	8
Nuclear decommissioning trusts:[a]				
Domestic equity	583	85	—	668
Foreign equity	34	184	—	218
U.S. Treasury and government agency securities	—	130	—	130
Municipal bonds	—	62	—	62
Corporate bonds	—	299	—	299
Mortgage and asset backed securities	—	139	—	139
Other	11	13	3	27
Cash equivalents	397	—	—	397
Other investments	9	—	1	10
Total	$ 1,034	$ 933	$ 4	$ 1,971
Liabilities:				
Energy-related derivatives	$ —	$ 201	$ —	$ 201
Interest rate derivatives	—	24	—	24
Total	$ —	$ 225	$ —	$ 225

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

As of December 31, 2013, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2013:	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	$ —	$ 24	$ —	$ 24
Interest rate derivatives	—	3	—	3
Nuclear decommissioning trusts:[(a)]				
Domestic equity	589	75	—	664
Foreign equity	35	196	—	231
U.S. Treasury and government agency securities	—	103	—	103
Municipal bonds	—	64	—	64
Corporate bonds	—	229	—	229
Mortgage and asset backed securities	—	132	—	132
Other	—	37	3	40
Cash equivalents	491	—	—	491
Other investments	9	—	4	13
Total	$ 1,124	$ 863	$ 7	$ 1,994
Liabilities:				
Energy-related derivatives	$ —	$ 56	$ —	$ 56

(a) 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 financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally, implied volatility of interest rate options. See Note 11 for additional information on how these derivatives are used.

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' judgment, are also obtained when available.

Investments in private equity and real estate within the nuclear decommissioning trusts are generally classified as Level 3, as the underlying assets typically do not have observable inputs. The fund manager values these assets using various inputs and techniques depending on the nature of the underlying investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

"Other investments" include investments that are not traded in the open market. The fair value of these investment have been determined based on market factors including comparable multiples and the expectations regarding cash flows and business plan executions.

As of December 31, 2014 and 2013, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2014:	*(in millions)*			
Nuclear decommissioning trusts:				
Foreign equity funds	$ 121	None	Monthly	5 days
Equity – commingled funds	63	None	Daily/Monthly	Daily/7 days
Debt – commingled funds	15	None	Daily	5 days
Other – commingled funds	8	None	Daily	Not applicable
Other – money market funds	11	None	Daily	Not applicable
Trust-owned life insurance	115	None	Daily	15 days
Cash equivalents:				
Money market funds	397	None	Daily	Not applicable
As of December 31, 2013:				
Nuclear decommissioning trusts:				
Foreign equity funds	$ 131	None	Monthly	5 days
Corporate bonds – commingled funds	8	None	Daily	Not applicable
Equity – commingled funds	65	None	Daily/Monthly	Daily/7 days
Other – commingled funds	24	None	Daily	Not applicable
Trust-owned life insurance	110	None	Daily	15 days
Cash equivalents:				
Money market funds	491	None	Daily	Not applicable

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have the Funds to comply with the NRC's regulations. The foreign equity fund in Georgia Power's nuclear decommissioning trusts seeks to provide long-term capital appreciation. In pursuing this investment objective, the foreign equity fund primarily invests in a diversified portfolio of equity securities of foreign companies, including those in emerging markets. These equity securities may include, but are not limited to, common stocks, preferred stocks, real estate investment trusts, convertible securities, depositary receipts, including American depositary receipts, European depositary receipts, and global depositary receipts; and rights and warrants to buy common stocks. Georgia Power may withdraw all or a portion of its investment on the last business day of each month subject to a minimum withdrawal of $1 million, provided that a minimum investment of $10 million remains. If notices of withdrawal exceed 20% of the aggregate value of the foreign equity fund, then the foreign equity fund's board may refuse to permit the withdrawal of all such investments and may scale down the amounts to be withdrawn pro rata and may further determine that any withdrawal that has been postponed will have priority on the subsequent withdrawal date.

The other-commingled funds and other-money market funds in Georgia Power's nuclear decommissioning trusts are invested primarily in a diversified portfolio of high quality, short-term, liquid debt securities. The funds represent the cash collateral received under the Funds' managers' securities lending program and/or the excess cash held within each separate investment account. The primary objective of the funds is to provide a high level of current income consistent with stability of principal and liquidity. The funds invest primarily in, but not limited to, commercial paper, floating and variable rate demand notes, debt securities issued or guaranteed by the U.S. government or its agencies or instrumentalities, time deposits, repurchase agreements, municipal obligations, notes, and other high-quality short-term liquid debt securities that mature in 90 days or less. Redemptions are available on a same day basis up to the full amount of the investment in the funds. See Note 1 under "Nuclear Decommissioning" for additional information.

Alabama Power's nuclear decommissioning trusts include investments in TOLI. The taxable nuclear decommissioning trusts invest in the TOLI in order to minimize the impact of taxes on the portfolios and can draw on the value of the TOLI through death

proceeds, loans against the cash surrender value, and/or the cash surrender value, subject to legal restrictions. The amounts reported in the table above reflect the fair value of investments the insurer has made in relation to the TOLI agreements. The nuclear decommissioning trusts do not own the underlying investments, but the fair value of the investments approximates the cash surrender value of the TOLI policies. The investments made by the insurer are in commingled funds. These commingled funds, along with other equity and debt commingled funds held in Alabama Power's nuclear decommissioning trusts, primarily include investments in domestic and international equity securities and predominantly high-quality fixed income securities. These fixed income securities may include U.S. Treasury and government agency fixed income securities, non-U.S. government and agency fixed income securities, domestic and foreign corporate fixed income securities, and mortgage and asset backed securities. The passively managed funds seek to replicate the performance of a related index. The actively managed funds seek to exceed the performance of a related index through security analysis and selection. See Note 1 under "Nuclear Decommissioning" for additional information.

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2014 and 2013, 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:		
2014	**$ 24,015**	**$ 25,816**
2013	$ 21,650	$ 22,197

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 Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power.

11. DERIVATIVES

Southern Company, the traditional operating companies, and Southern Power are exposed to market risks, primarily commodity price risk, interest rate risk, and occasionally foreign currency 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 gross basis. See Note 10 herein 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 and the cash impacts of settled foreign currency derivatives are recorded as investing activities.

Energy-Related Derivatives

The traditional operating companies and Southern Power enter 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 traditional operating companies have limited exposure to market volatility in commodity fuel prices and prices of electricity. Each of the traditional operating companies manages fuel-hedging programs, implemented per the guidelines of their respective state PSCs, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. The traditional operating companies (with respect to wholesale generating capacity) and Southern Power have limited exposure to market volatility in commodity fuel prices and prices of electricity because their 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 sales from its uncontracted generating capacity. Further, the traditional operating companies may be exposed to market volatility in energy-related commodity prices to the extent any uncontracted wholesale generating capacity is used to sell electricity.

To mitigate residual risks relative to movements in electricity prices, the traditional operating companies and Southern Power may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the traditional operating companies and Southern Power may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of three methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the traditional operating companies' 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 and 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, 2014, the net volume of energy-related derivative contracts for natural gas positions totaled 244 million mmBtu for the Southern Company system, with the longest hedge date of 2019 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 2017 for derivatives not designated as hedges.

In addition to the volumes discussed above, the traditional 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 6 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, 2015 are immaterial 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.

At December 31, 2014, 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, 2014
	(in millions)				*(in millions)*
Cash Flow Hedges of Forecasted Debt					
	$200	3-month LIBOR	2.93%	October 2025	$ (8)
	350	3-month LIBOR	2.57%	May 2025	(6)
	350	3-month LIBOR	2.57%	November 2025	(2)
Cash Flow Hedges of Existing Debt					
	250	3-month LIBOR + 0.32%	0.75%	March 2016	—
	200	3-month LIBOR + 0.40%	1.01%	August 2016	—
Fair Value Hedges of Existing Debt					
	250	1.30%	3-month LIBOR + 0.17%	August 2017	1
	250	5.40%	3-month LIBOR + 4.02%	June 2018	(1)
	200	4.25%	3-month LIBOR + 2.46%	December 2019	—
Total	$2,050				$ (16)

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the next 12-month period ending December 31, 2015 are immaterial. The Company has deferred gains and losses that are expected to be amortized into earnings through 2037.

Foreign Currency Derivatives

Southern Company and certain subsidiaries may enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates arising from purchases of equipment denominated in a currency other than U.S. dollars. Derivatives related to a firm commitment in a foreign currency transaction are accounted for as a fair value hedge where the derivatives' fair value gains or losses and the hedged items' fair value gains or losses are both recorded directly to earnings. Derivatives related to a forecasted transaction 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. Any ineffectiveness is recorded directly to earnings; however, Mississippi Power has regulatory approval allowing it to defer any ineffectiveness associated with firm commitments related to the Kemper IGCC to a regulatory asset. At December 31, 2014, there were no foreign currency derivatives outstanding.

Derivative Financial Statement Presentation and Amounts

At December 31, 2014 and 2013, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 7**	$ 16	Other current liabilities	**$ 118**	$ 26
	Other deferred charges and assets	**—**	7	Other deferred credits and liabilities	**79**	29
Total derivatives designated as hedging instruments for regulatory purposes		**$ 7**	$ 23		**$ 197**	$ 55
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:	Other current assets	**$ 7**	$ 3	Other current liabilities	**$ 17**	$ —
	Other deferred charges and assets	**1**	—	Other deferred credits and liabilities	**7**	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges		**$ 8**	$ 3		**$ 24**	$ —
Derivatives not designated as hedging instruments						
Energy-related derivatives	Other current assets	**$ 6**	$ —	Other current liabilities	**$ 4**	$ 1
	Other deferred charges and assets	**—**	1	Other deferred credits and liabilities	**—**	—
Total derivatives not designated as hedging instruments		**$ 6**	$ 1		**$ 4**	$ 1
Total		**$ 21**	$ 27		**$ 225**	$ 56

The Company's derivative contracts are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related 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. Amounts related to energy-related derivative contracts and interest rate derivative contracts at December 31, 2014 and 2013 are presented in the following tables.

	Fair Value			
Assets	**2014**	2013	**Liabilities**	**2014**	2013
	(in millions)			*(in millions)*	
Energy-related derivatives presented in the Balance Sheet [a]	$ 13	$ 24	Energy-related derivatives presented in the Balance Sheet [a]	$ 201	$ 56
Gross amounts not offset in the Balance Sheet [b]	(9)	(22)	Gross amounts not offset in the Balance Sheet [b]	(9)	(22)
Net energy-related derivative assets	$ 4	$ 2	**Net energy-related derivative liabilities**	$ 192	$ 34
Interest rate derivatives presented in the Balance Sheet [a]	$ 8	$ 3	Interest rate derivatives presented in the Balance Sheet [a]	$ 24	$ —
Gross amounts not offset in the Balance Sheet [b]	(8)	—	Gross amounts not offset in the Balance Sheet [b]	(8)	—
Net interest rate derivative assets	$ —	$ 3	**Net interest rate derivative liabilities**	$ 16	$ —

(a) The Company does not offset fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.

(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

At December 31, 2014 and 2013, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

	Unrealized Losses			Unrealized Gains			
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	$ (118)	$ (26)	Other regulatory liabilities, current	$ 7	$ 16
	Other regulatory assets, deferred	(79)	(29)	Other regulatory liabilities, deferred	—	7
Total energy-related derivative gains (losses)		$ (197)	$ (55)		$ 7	$ 23

For the years ended December 31, 2014, 2013, and 2012, the pre-tax effects of interest rate and foreign currency derivatives designated as fair value hedging instruments on the statements of income were immaterial on a gross basis for Southern Company. Furthermore, the pre-tax effects of interest rate derivatives designated as fair value hedging instruments on Southern Company's statements of income were offset by changes to the carrying value of long-term debt and the pre-tax effects of foreign currency derivatives designated as fair value hedging instruments on Southern Company's statements of income were offset by changes in the fair value of the purchase commitment related to equipment purchases.

For the years ended December 31, 2014, 2013, and 2012, the pre-tax effects of energy-related derivatives and interest rate derivatives designated as cash flow hedging instruments recognized in OCI and those reclassified from OCI into earnings were immaterial for Southern Company.

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2014, 2013, and 2012, the pre-tax effects of energy-related and foreign currency derivatives not designated as hedging instruments on the statements of income were immaterial for Southern Company.

For the Southern Company system's energy-related derivatives not designated as hedging instruments, a portion of the pre-tax realized and unrealized gains and losses was associated with hedging fuel price risk of certain PPA customers and had no impact on net income or on fuel expense as presented in the Company's statements of income for the years ended December 31, 2014, 2013, and 2012. This third party hedging activity has been discontinued.

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, 2014, Southern Company's collateral posted with its derivative counterparties was immaterial.

At December 31, 2014, the fair value of derivative liabilities with contingent features was $54 million. The maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $54 million and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

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

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

12. SEGMENT AND RELATED INFORMATION

The primary business of the Southern Company system is electricity sales by the traditional operating companies and Southern Power. The four traditional 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's reportable business segments are the sale of electricity by the four traditional operating companies and Southern Power. Revenues from sales by Southern Power to the traditional operating companies were $383 million, $346 million, and $425 million in 2014, 2013, and 2012, respectively. The "All Other" column includes parent Southern Company, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include 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, 2014, 2013, and 2012 was as follows:

	Electric Utilities						
	Traditional Operating Companies	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
				(in millions)			
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**
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	**64,644**	**5,550**	**(131)**	**70,063**	**1,156**	**(296)**	**70,923**
Gross property additions	**5,568**	**942**	**—**	**6,510**	**11**	**1**	**6,522**
2013							
Operating revenues	$ 16,136	$ 1,275	$ (376)	$17,035	$ 139	$ (87)	$ 17,087
Depreciation and amortization	1,711	175	—	1,886	15	—	1,901
Interest income	17	1	—	18	2	(1)	19
Interest expense	714	74	—	788	36	—	824
Income taxes	889	46	—	935	(85)	(1)	849
Segment net income (loss)[a] [b]	1,486	166	—	1,652	(10)	2	1,644
Total assets	59,447	4,429	(101)	63,775	1,077	(306)	64,546
Gross property additions	5,226	633	—	5,859	9	—	5,868
2012							
Operating revenues	$ 15,730	$ 1,186	$ (438)	$16,478	$ 141	$ (82)	$ 16,537
Depreciation and amortization	1,629	143	—	1,772	15	—	1,787
Interest income	21	1	—	22	19	(1)	40
Interest expense	757	63	—	820	39	—	859
Income taxes	1,307	93	—	1,400	(66)	—	1,334
Segment net income (loss)[a]	2,145	175	1	2,321	33	(4)	2,350
Total assets	58,600	3,780	(129)	62,251	1,116	(218)	63,149
Gross property additions	4,813	241	—	5,054	5	—	5,059

(a) After dividends on preferred and preference stock of subsidiaries.

(b) Segment net income (loss) for the traditional operating companies in 2014 and 2013 includes $868 million in pre-tax charges ($536 million after tax) and $1.2 billion in pre-tax charges ($729 million after tax), respectively, for estimated probable losses on the Kemper IGCC. See Note 3 under "Integrated Coal Gasification Combined Cycle – Kemper IGCC Schedule and Cost Estimate" for additional information.

Products and Services

	Electric Utilities' Revenues			
Year	Retail	Wholesale	Other	Total
		(in millions)		
2014	**$15,550**	**$2,184**	**$672**	**$18,406**
2013	14,541	1,855	639	17,035
2012	14,187	1,675	616	16,478

13. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2014 and 2013 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	Per Common Share				
				Basic Earnings	Diluted Earnings	Dividends	Trading Price Range	
							High	Low
		(in millions)						
March 2014	**$ 4,644**	**$ 700**	**$ 351**	**$ 0.39**	**$ 0.39**	**$ 0.5075**	**$ 44.00**	**$ 40.27**
June 2014	**4,467**	**1,103**	**611**	**0.68**	**0.68**	**0.5250**	**46.81**	**42.55**
September 2014	**5,339**	**1,278**	**718**	**0.80**	**0.80**	**0.5250**	**45.47**	**41.87**
December 2014	**4,017**	**561**	**283**	**0.31**	**0.31**	**0.5250**	**51.28**	**43.55**
March 2013	$ 3,897	$ 325	$ 81	$ 0.09	$ 0.09	$ 0.4900	$ 46.95	$ 42.82
June 2013	4,246	640	297	0.34	0.34	0.5075	48.74	42.32
September 2013	5,017	1,491	852	0.97	0.97	0.5075	45.75	40.63
December 2013	3,927	799	414	0.47	0.47	0.5075	42.94	40.03

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 $70.0 million ($43.2 million after tax) in the fourth quarter 2014, $418.0 million ($258.1 million after tax) in the third quarter 2014, $380.0 million ($234.7 million after tax) in the first quarter 2014, $40.0 million ($24.7 million after tax) in the fourth quarter 2013, $150.0 million ($92.6 million after tax) in the third quarter 2013, $450.0 million ($277.9 million after tax) in the second quarter 2013, and $540.0 million ($333.5 million after tax) in the first quarter 2013. In the aggregate, Southern Company has incurred charges of $2.05 billion ($1.26 billion after tax) as a result of changes in the cost estimate for the Kemper IGCC through December 31, 2014. 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 2010 through 2014
Southern Company and Subsidiary Companies 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in millions)	$ 18,467	$ 17,087	$ 16,537	$ 17,657	$ 17,456
Total Assets (in millions)	$ 70,923	$ 64,546	$ 63,149	$ 59,267	$ 55,032
Gross Property Additions (in millions)	$ 6,522	$ 5,868	$ 5,059	$ 4,853	$ 4,443
Return on Average Common Equity (percent)	10.08	8.82	13.10	13.04	12.71
Cash Dividends Paid Per Share of Common Stock	$ 2.0825	$ 2.0125	$ 1.9425	$ 1.8725	$ 1.8025
Consolidated Net Income After Preferred and Preference Stock of Subsidiaries (in millions)	$ 1,963	$ 1,644	$ 2,350	$ 2,203	$ 1,975
Earnings Per Share —					
Basic	$ 2.19	$ 1.88	$ 2.70	$ 2.57	$ 2.37
Diluted	2.18	1.87	2.67	2.55	2.36
Capitalization (in millions):					
Common stock equity	$ 19,949	$ 19,008	$ 18,297	$ 17,578	$ 16,202
Preferred and preference stock of subsidiaries and noncontrolling interest	977	756	707	707	707
Redeemable preferred stock of subsidiaries	375	375	375	375	375
Redeemable noncontrolling interest	39	—	—	—	—
Long-term debt	20,841	21,344	19,274	18,647	18,154
Total (excluding amounts due within one year)	$ 42,181	$ 41,483	$ 38,653	$ 37,307	$ 35,438
Capitalization Ratios (percent):					
Common stock equity	47.3	45.8	47.3	47.1	45.7
Preferred and preference stock of subsidiaries and noncontrolling interest	2.3	1.8	1.8	1.9	2.0
Redeemable preferred stock of subsidiaries	0.9	0.9	1.0	1.0	1.1
Redeemable noncontrolling interest	0.1	—	—	—	—
Long-term debt	49.4	51.5	49.9	50.0	51.2
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	$ 21.98	$ 21.43	$ 21.09	$ 20.32	$ 19.21
Market price per share:					
High	$ 51.28	$ 48.74	$ 48.59	$ 46.69	$ 38.62
Low	43.55	40.03	41.75	35.73	30.85
Close (year-end)	49.11	41.11	42.81	46.29	38.23
Market-to-book ratio (year-end) (percent)	223.4	191.8	203.0	227.8	199.0
Price-earnings ratio (year-end) (times)	22.4	21.9	15.9	18.0	16.1
Dividends paid (in millions)	$ 1,866	$ 1,762	$ 1,693	$ 1,601	$ 1,496
Dividend yield (year-end) (percent)	4.2	4.9	4.5	4.0	4.7
Dividend payout ratio (percent)	95.0	107.1	72.0	72.7	75.7
Shares outstanding (in thousands):					
Average	897,194	876,755	871,388	856,898	832,189
Year-end	907,777	887,086	867,768	865,125	843,340
Stockholders of record (year-end)	137,369	143,800	149,628	155,198	160,426
Traditional Operating Company Customers (year-end) (in thousands):					
Residential	3,890	3,859	3,832	3,809	3,813
Commercial*	587	582	579	578	579
Industrial*	16	16	16	16	15
Other	11	10	9	9	10
Total	4,504	4,467	4,436	4,412	4,417
Employees (year-end)	26,369	26,300	26,439	26,377	25,940

* A reclassification of customers from commercial to industrial is reflected for years 2010-2013 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 CONSOLIDATED FINANCIAL AND OPERATING DATA (continued)
For the Periods Ended December 2010 through 2014
Southern Company and Subsidiary Companies 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in millions):					
Residential	$ 6,499	$ 6,011	$ 5,891	$ 6,268	$ 6,319
Commercial	5,469	5,214	5,097	5,384	5,252
Industrial	3,449	3,188	3,071	3,287	3,097
Other	133	128	128	132	123
Total retail	15,550	14,541	14,187	15,071	14,791
Wholesale	2,184	1,855	1,675	1,905	1,994
Total revenues from sales of electricity	17,734	16,396	15,862	16,976	16,785
Other revenues	733	691	675	681	671
Total	$ 18,467	$ 17,087	$ 16,537	$ 17,657	$ 17,456
Kilowatt-Hour Sales (in millions):					
Residential	53,347	50,575	50,454	53,341	57,798
Commercial	53,243	52,551	53,007	53,855	55,492
Industrial	54,140	52,429	51,674	51,570	49,984
Other	909	902	919	936	943
Total retail	161,639	156,457	156,054	159,702	164,217
Wholesale sales	32,786	26,944	27,563	30,345	32,570
Total	194,425	183,401	183,617	190,047	196,787
Average Revenue Per Kilowatt-Hour (cents):					
Residential	12.18	11.89	11.68	11.75	10.93
Commercial	10.27	9.92	9.62	10.00	9.46
Industrial	6.37	6.08	5.94	6.37	6.20
Total retail	9.62	9.29	9.09	9.44	9.01
Wholesale	6.66	6.88	6.08	6.28	6.12
Total sales	9.12	8.94	8.64	8.93	8.53
Average Annual Kilowatt-Hour Use Per Residential Customer	13,765	13,144	13,187	13,997	15,176
Average Annual Revenue Per Residential Customer	$ 1,679	$ 1,562	$ 1,540	$ 1,645	$ 1,659
Plant Nameplate Capacity Ratings (year-end) (megawatts)	46,549	45,502	45,740	43,555	42,961
Maximum Peak-Hour Demand (megawatts):					
Winter	37,234	27,555	31,705	34,617	35,593
Summer	35,396	33,557	35,479	36,956	36,321
System Reserve Margin (at peak) (percent)*	19.8	21.5	20.8	19.2	23.3
Annual Load Factor (percent)	59.6	63.2	59.5	59.0	62.2
Plant Availability (percent):**					
Fossil-steam	85.8	87.7	89.4	88.1	91.4
Nuclear	91.5	91.5	94.2	93.0	92.1
Source of Energy Supply (percent):					
Coal	39.3	36.9	35.2	48.7	55.0
Nuclear	14.8	15.5	16.2	15.0	14.1
Hydro	2.5	3.9	1.7	2.1	2.5
Oil and gas	37.4	37.3	38.3	28.0	23.7
Purchased power	6.0	6.4	8.6	6.2	4.7
Total	100.0	100.0	100.0	100.0	100.0

* Beginning in 2014, system reserve margin is calculated to include unrecognized capacity.

** Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

[This page intentionally left blank]

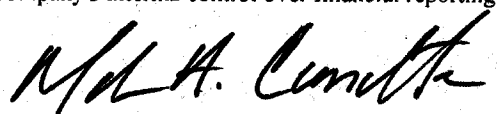
ALABAMA POWER COMPANY

FINANCIAL SECTION

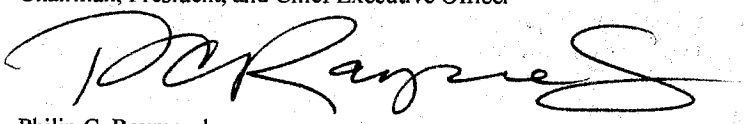
MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Alabama Power Company 2014 Annual Report

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, 2014.



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



Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer
March 2, 2015

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, 2014 and 2013, 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, 2014. 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-148 to II-194) present fairly, in all material respects, the financial position of Alabama Power Company as of December 31, 2014 and 2013, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Birmingham, Alabama
March 2, 2015

DEFINITIONS

Term	Meaning
AFUDC	Allowance for funds used during construction
ASC	Accounting Standards Codification
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
FERC	Federal Energy Regulatory Commission
GAAP	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 operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
Rate CNP	Rate Certificated New Plant
Rate CNP Environmental	Rate Certificated New Plant Environmental
Rate CNP PPA	Rate Certificated New Plant Power Purchase Agreement
Rate ECR	Rate energy cost recovery
Rate NDR	Natural disaster reserve rate
Rate RSE	Rate stabilization and equalization plan
ROE	Return on equity
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, 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 system	The Southern Company, the traditional operating companies, Southern Power, SEGCO, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional operating companies	Alabama Power Company, Georgia Power, Gulf Power, and Mississippi Power

OVERVIEW

Business Activities

Alabama Power Company (the Company) operates as a vertically integrated utility providing electricity 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 selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, fuel, capital expenditures, 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.

Key Performance Indicators

The Company continues to focus on several key performance indicators including customer satisfaction, plant availability, system reliability, and net income after dividends on 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, which the Company achieved during 2014.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The Company's fossil/hydro 2014 Peak Season EFOR of 2.5% was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The Company's performance for 2014 was better than the target for these transmission and distribution reliability measures.

The Company uses net income after dividends on preferred and preference stock as the primary measure of the Company's financial performance. In 2014, the Company achieved its targeted net income after dividends on preferred and preference stock.

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

Earnings

The Company's 2014 net income after dividends on preferred and preference stock was $761 million, representing a $49 million, or 6.9%, increase over the previous year. The increase was due primarily to an increase in weather-related revenues resulting from colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013, an increase in revenues related to net investments under Rate CNP Environmental, and an increase in AFUDC resulting from increased capital expenditures. The factors increasing net income were partially offset by an increase in total operating expenses.

The Company's 2013 net income after dividends on preferred and preference stock of $712 million increased $8 million, or 1.1%, from the prior year. The increase in net income was due primarily to more favorable weather-related revenues in 2013 compared to 2012, an increase in AFUDC resulting from increased capital expenditures, and a decrease in interest expense resulting from lower interest rates. The factors increasing net income were partially offset by a decrease in revenues related to net investment under Rate CNP Environmental and a decrease in wholesale revenues to municipalities.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2014	2014	2013
		(in millions)	
Operating revenues	$ 5,942	$ 324	$ 98
Fuel	1,605	(26)	128
Purchased power	385	156	(26)
Other operations and maintenance	1,468	179	2
Depreciation and amortization	603	(42)	6
Taxes other than income taxes	356	8	8
Total operating expenses	4,417	275	118
Operating income	1,525	49	(20)
Allowance for equity funds used during construction	49	17	13
Interest income	15	(1)	—
Interest expense, net of amounts capitalized	(255)	(4)	(28)
Other income (expense), net	(22)	14	(12)
Income taxes	512	34	1
Net income	800	49	8
Dividends on preferred and preference stock	39	—	—
Net income after dividends on preferred and preference stock	$ 761	$ 49	$ 8

Operating Revenues

Operating revenues for 2014 were $5.9 billion, reflecting a $324 million increase from 2013. Details of operating revenues were as follows:

	Amount	
	2014	2013
	(in millions)	
Retail — prior year	$ 4,952	$ 4,933
Estimated change resulting from —		
Rates and pricing	81	(18)
Sales growth	7	4
Weather	85	21
Fuel and other cost recovery	124	12
Retail — current year	5,249	4,952
Wholesale revenues —		
Non-affiliates	281	248
Affiliates	189	212
Total wholesale revenues	470	460
Other operating revenues	223	206
Total operating revenues	$ 5,942	$ 5,618
Percent change	5.8%	1.8%

Retail revenues in 2014 were $5.2 billion. These revenues increased $297 million, or 6.0%, in 2014 and increased $19 million, or 0.4%, in 2013, each as compared to the prior year. The increase in 2014 was due to increased fuel revenues, colder weather in the

first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013, and increased revenues related to net investments under Rate CNP Environmental primarily resulting from the inclusion of pre-2005 environmental assets. The increase in 2013 was due to more favorable weather, increased fuel revenues and increased revenues associated with Rate CNP PPA. The increase in 2013 was partially offset by a reduction in revenues related to net investments under Rate CNP Environmental. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information. See "Energy Sales" 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:

	2014	2013	2012
		(in millions)	
Capacity and other	$ 154	$ 143	$ 160
Energy	127	105	117
Total non-affiliated	$ 281	$ 248	$ 277

Wholesale revenues from sales to non-affiliates will vary depending on the market prices of available wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and 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 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 2014, wholesale revenues from sales to non-affiliates increased $33 million, or 13.3%, as compared to the prior year primarily due to the availability of the Company's lower cost generation. This increase reflects a $22 million increase in revenues from energy sales and an $11 million increase in capacity revenues. In 2014, KWH sales increased 12.3% primarily due to the availability of the Company's lower cost generation and a 1.1% increase in the price of energy primarily due to higher natural gas prices. In 2013, wholesale revenues from sales to non-affiliates decreased $29 million, or 10.5%, as compared to the prior year due to a $17 million decrease in capacity revenues and a $12 million decrease in revenues from energy sales. In 2013, KWH sales decreased 11.3% primarily from decreased sales to municipalities, partially offset by a 0.8% increase in the price of energy.

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 clauses.

In 2014, wholesale revenues from sales to affiliates decreased $23 million, or 10.8%, as compared to the prior year primarily related to a decrease in revenue from energy sales. In 2014, KWH sales decreased 21.7% primarily due to decreased hydro generation as the result of less rainfall as well as the addition of new generation in the Southern Company system, partially offset by a 13.7% increase in the price of energy primarily due to higher natural gas prices. In 2013, wholesale revenues from sales to affiliates increased $101 million, or 91.0%, as compared to the prior year primarily due to a $103 million increase in energy sales, partially offset by a $2 million decrease in capacity revenues. In 2013, KWH sales increased 88.9% and there was a 1.3% increase in the price of energy.

In 2014, other operating revenues increased $17 million, or 8.3%, as compared to the prior year primarily due to increases in open access transmission tariff revenues, transmission service agreement revenues, and co-generation steam 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 2014 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2014	2014	2013	2014	2013
	(in billions)				
Residential	**18.7**	**4.5%**	1.7%	**(0.8)%**	(1.1)%
Commercial	**14.1**	**1.6**	(0.5)	**(1.3)**	0.5
Industrial	**23.8**	**3.9**	3.4	**3.9**	3.4
Other	**0.2**	**—**	(1.4)	**—**	(1.4)
Total retail	**56.8**	**3.5**	1.8	**1.0 %**	1.1 %
Wholesale —					
Non-affiliates	**4.6**	**12.3**	(10.8)		
Affiliates	**5.7**	**(21.7)**	88.9		
Total wholesale	**10.3**	**(9.4)**	34.5		
Total energy sales	**67.1**	**1.3%**	6.3%		

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales in 2014 were 3.5% higher than in 2013. Residential and commercial sales increased 4.5% and 1.6%, respectively, due primarily to colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013. Weather-adjusted residential and commercial sales decreased 0.8% and 1.3%, respectively, due primarily to a decrease in customer demand in 2014 compared to 2013. Industrial sales increased 3.9% in 2014 compared to 2013 as a result of an increase in demand resulting from changes in production levels primarily in the primary metals, chemicals, automotive and plastics, and stone, clay, and glass sectors. Household income, one of the primary drivers of residential customer usage, was flat in 2014.

Retail energy sales in 2013 were 1.8% higher than in 2012. Residential sales increased 1.7%, due primarily to more favorable weather in 2013. Weather-adjusted residential sales decreased 1.1% in 2013, primarily due to a decrease in customer demand. Commercial sales and weather-adjusted commercial sales remained relatively flat in 2013 compared to 2012. Industrial sales increased 3.4% in 2013 compared to 2012 as a result of an increase in demand resulting from changes in production levels primarily in the chemicals, primary metals, and stone, clay, and glass sectors.

Weather adjusted wholesale non-affiliate KWH sales decreased 8.0% in 2014 and 11.0% in 2013 due primarily to a decrease in demand from municipalities. 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 the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

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

	2014	2013	2012
Total generation *(billions of KWHs)*	**63.6**	65.3	59.9
Total purchased power *(billions of KWHs)*	**6.6**	4.0	5.4
Sources of generation *(percent)* —			
Coal	**54**	53	53
Nuclear	**23**	21	25
Gas	**17**	17	18
Hydro	**6**	9	4
Cost of fuel, generated *(cents per net KWH)* —			
Coal	**3.14**	3.29	3.30
Nuclear	**0.84**	0.84	0.80
Gas	**3.69**	3.38	3.06
Average cost of fuel, generated *(cents per net KWH)**	**2.68**	2.73	2.61
Average cost of purchased power *(cents per net KWH)***	**5.92**	5.76	4.86

* KWHs generated by hydro are excluded from the average cost of fuel, generated.

** 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 $2.0 billion in 2014, an increase of $130 million, or 7.0%, compared to 2013. The increase was primarily due to a $147 million increase related to the volume of KWHs purchased and a $10 million increase in the average cost of purchased power. These increases were partially offset by a $19 million decrease in the average cost of fuel and an $8 million decrease in the volume of KWHs generated.

Fuel and purchased power expenses were $1.9 billion in 2013, an increase of $102 million, or 5.8%, compared to 2012. The increase was primarily due to a $95 million increase in the volume of KWHs generated, a $38 million increase in the average cost of fuel, and a $37 million increase in the average cost of purchased power. These increases were partially offset by a $68 million decrease related to the volume of KWHs purchased.

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

Fuel

Fuel expenses were $1.6 billion in 2014, a decrease of $26 million, or 1.6%, compared to 2013. The decrease was primarily due to a 4.5% decrease in the average cost of KWHs generated by coal, partially offset by a 30.8% decrease in the volume of KWHs generated by hydro facilities as a result of less rainfall, and a 9.2% increase in the average cost of KWHs generated by natural gas, which excludes tolling agreements. Fuel expenses were $1.6 billion in 2013, an increase of $128 million, or 8.5%, compared to 2012. This increase was primarily due to a 10.5% increase in the average cost of KWHs generated by natural gas, which excludes tolling agreements, and a 9.9% increase in KWHs generated by coal. This was partially offset by a 110.9% increase in the volume of KWHs generated by hydro facilities resulting from greater rainfall.

Purchased Power – Non-Affiliates

In 2014, purchased power expense from non-affiliates was $185 million, an increase of $85 million, or 85.0%, compared to 2013. The increase was primarily due to a 42.1% increase in the average cost per KWH purchased primarily due to demand during peak periods and a 28.8% increase in the amount of energy purchased to meet the demand created during cold weather in the first quarter 2014 and the addition of a new PPA in 2014. In 2013, purchased power expense from non-affiliates was $100 million, an increase of $27 million, or 37.0%, compared to 2012. The increase over the prior year was primarily due to a 52.6% increase in the amount of energy purchased, partially offset by a 17.2% decrease in the average cost per KWH.

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

Purchased Power – Affiliates

Purchased power expense from affiliates was $200 million in 2014, an increase of $71 million, or 55.0%, compared to 2013. This increase was primarily due to a 96.4% increase in the amount of energy purchased to meet the demand created during cold weather in the first quarter 2014, partially offset by a 20.8% decrease in the average cost per KWH purchased due to the availability of lower cost Southern Company system generation at the time of purchase. Purchased power expense from affiliates was $129 million in 2013, a decrease of $53 million, or 29.1%, compared to 2012. This decrease was primarily due to a 50.4% decrease in the amount of energy purchased, partially offset by a 42.5% increase in the average cost per KWH.

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 2014, other operations and maintenance expenses increased $179 million, or 13.9%, as compared to the prior year. Steam production, other power generation, and hydro generation expenses increased $110 million primarily due to scheduled outage costs. See Note 3 to the financial statements under "Retail Regulatory Matters – Cost of Removal Accounting Order" for additional information. Distribution and transmission expenses increased $31 million primarily related to increases in maintenance and labor expenses. Nuclear production expenses increased $14 million primarily related to labor expenses.

Depreciation and Amortization

Depreciation and amortization decreased $42 million, or 6.5%, in 2014 as compared to the prior year. The decrease in 2014 was primarily due to the amortization of $120 million of the regulatory liability for other cost of removal obligations, partially offset by increases due to depreciation rates related to environmental assets and amortization of certain regulatory assets. See Note 3 to the financial statements under "Retail Regulatory Matters – Cost of Removal Accounting Order" for additional information. In 2013, depreciation and amortization increased $6 million, or 0.9%, as compared to the prior year. The increase in 2013 was primarily due to an increase in depreciation related to environmental assets, additions to property, plant, and equipment related to distribution and transmission projects, as well as the amortization of software. These increases were partially offset by the deferral of certain expenses under an accounting order. See Note 3 to the financial statements under "Retail Regulatory Matters – Compliance and Pension Cost Accounting Order" for additional information. The increase related to environmental assets was offset by revenues under Rate CNP Environmental.

Allowance for Equity Funds Used During Construction

AFUDC equity increased $17 million, or 53.1%, in 2014 as compared to the prior year primarily due to an increase in capital expenditures related to environmental and steam generation. AFUDC equity increased $13 million, or 68.4%, in 2013 as compared to the prior year primarily due to increased capital expenditures associated with environmental, steam and nuclear generating facilities, and transmission. 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 decreased $28 million, or 9.8%, in 2013. The decrease in 2013 was primarily due to a decrease in interest rates and the timing of issuances and redemptions of long-term debt.

Other Income (Expense), Net

Other income (expense), net increased $14 million, or 38.9%, in 2014 as compared to the prior year primarily due to a decrease in non-operating expenses and an increase in sales of non-utility property. Other income (expense), net decreased $12 million, or 50.0%, in 2013 as compared to the prior year primarily due to increases in donations, partially offset by increases in non-operating income related to gains on sales of non-utility property.

Income Taxes

Income taxes increased $34 million, or 7.1%, in 2014 as compared to the prior year primarily due to higher pre-tax earnings.

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 electricity to retail and wholesale customers within its traditional service area located in the State of Alabama in addition 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 – Electric Utility Regulation" 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. Future earnings in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, 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. Changes in regional and global economic conditions may impact sales for the Company, as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

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. 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.

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against the Company alleging violations of the New Source Review provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by Mississippi Power. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. See Note 3 to the financial statements under "Environmental Matters – New Source Review Actions" for additional information. The ultimate outcome of these matters cannot be determined at this time.

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; 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 2014, the Company had invested approximately $3.6 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $355 million, $184 million, and $62 million for 2014, 2013, and 2012, respectively. The Company expects that capital expenditures to comply with existing environmental statutes and

regulations will total approximately $641 million from 2015 through 2017, with annual totals of approximately $417 million, $171 million, and $53 million for 2015, 2016, and 2017, respectively. Costs related to the proposed water and final CCR rules are not included in the estimated environmental capital expenditures. See "Capital Requirements and Contractual Obligations" for additional information regarding estimated incremental environmental compliance expenditures. In addition, these estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information.

The Company'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 and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time. See "Retail Regulatory Matters –Environmental Accounting Order" herein for additional information on planned unit retirements and fuel conversions at the Company.

Southern Electric Generating Company (SEGCO) is jointly owned with Georgia Power. As part of its environmental compliance strategy, SEGCO expects to complete the addition of natural gas as the primary fuel source for its generating units in 2015. The capacity of SEGCO's units is sold equally to the Company and Georgia Power through a PPA. If such compliance costs cannot continue to be recovered through retail rates, they could have a material financial impact on the Company's financial condition and results of operations. See Note 4 to the financial statements for additional information.

Compliance with any new federal or state legislation or regulations relating to air quality, water, CCR, global climate change, 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. Since 1990, the Company has spent approximately $3.4 billion in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2012, the EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015 up to April 16, 2016 for affected units for which extensions have been granted. On November 25, 2014, the U.S. Supreme Court granted a petition for review of the final MATS rule.

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 more stringent eight-hour ozone NAAQS, which it began to implement in 2011. In 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone NAAQS. All areas within the Company's service territory have achieved attainment of this standard. On December 17, 2014, the EPA published a proposed rule to further reduce the current eight-hour ozone standard. The EPA is required by federal court order to complete this rulemaking by October 1, 2015. Finalization of a lower eight-hour ozone standard could result in the designation of new ozone nonattainment areas within the Company's service territory.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS, and the EPA has officially redesignated former nonattainment areas within the service territory as attainment for these standards. In 2012, the EPA issued a final rule that increases the stringency of the annual fine particulate matter standard. The EPA promulgated final designations for the 2012 annual standard on December 18, 2014, and no new nonattainment areas were designated within the Company's service territory. The EPA has, however, deferred its designation decision for one area in Alabama, so future nonattainment designation of this area is possible.

Final revisions to the NAAQS for sulfur dioxide (SO_2), which established a new one-hour standard, became effective in 2010. No areas within the Company's service territory have been designated as nonattainment under this rule. However, the EPA has

announced plans to make additional designation decisions for SO_2 in the future, which could result in nonattainment designations for areas within the Company's service territory. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

On February 13, 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 March 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 co-owned with Mississippi Power and units owned by SEGCO, which is jointly owned with Georgia Power.

The Company's service territory is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I beginning in 2015 and Phase II beginning in 2017. In 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety, but on April 29, 2014, the U.S. Supreme Court overturned that decision and remanded the case back to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The U.S. Court of Appeals for the District of Columbia Circuit granted the EPA's motion to lift the stay of the rule, and the first phase of CSAPR took effect on January 1, 2015.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology to certain sources, including fossil fuel-fired generating facilities, built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter.

In 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units), during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

In February 2013, the EPA proposed a rule that would require certain states to revise 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 EPA proposed to supplement the 2013 proposed rule on September 17, 2014, making it more stringent. The EPA has entered into a settlement agreement requiring it to finalize the proposed rule by May 22, 2015. The proposed rule would require states subject to the rule (including Alabama) to revise their SSM provisions within 18 months after issuance of the final 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. As part of this strategy, the Company has developed a compliance plan for the MATS rule which includes reliance on existing emission control technologies, the construction of baghouses to provide an additional level of control on the emissions of mercury and particulates from certain generating units, the use of additives or other injection technology, the use of existing or additional natural gas capability, and unit retirements. Additionally, certain transmission system upgrades are required. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, the Alabama opacity rule, CSAPR, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. These regulations could result in significant additional 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.

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 on October 14, 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

In June 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing revised technology-based limits for certain wastestreams from steam electric power plants and best management practices for CCR surface impoundments. The EPA has entered into a consent decree requiring it to finalize revisions to the steam

electric effluent guidelines by September 30, 2015. The ultimate impact of the rule will also depend on the specific technology requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

On April 21, 2014, the EPA and the U.S. Army Corps of Engineers jointly published a proposed rule to revise the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs, which would significantly expand the scope of federal jurisdiction under the CWA. In addition, the rule as proposed could have significant impacts on economic development projects which could affect customer demand growth. The ultimate impact of the proposed rule will depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time. If finalized as proposed, 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.

These proposed and final water quality regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

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.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate 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 mandate 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 mandated closure of a CCR Unit. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $311 million and ongoing post-closure care of approximately $49 million. The Company will record asset retirement obligations (ARO) for the estimated closure costs required under the CCR Rule during 2015. SEGCO, which is jointly owned with Georgia Power, will also record an ARO for ash ponds commonly used at Plant E.C. Gaston. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Global Climate Issues

In 2014, the EPA published three sets of proposed standards that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. On January 8, 2014, the EPA published proposed standards for new units, and, on June 18, 2014, the EPA published proposed standards governing existing units, known as the Clean Power Plan, and separate standards governing CO_2 emissions from modified and reconstructed units. The EPA's proposed Clean Power Plan establishes guidelines for states to develop plans to address CO_2 emissions from existing fossil fuel-fired electric generating units. The EPA's proposed guidelines establish state-specific interim and final CO_2 emission rate goals to be achieved between 2020 and 2029 and 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. 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 market based contracts.

The Southern Company system filed comments on the EPA's proposed Clean Power Plan on December 1, 2014. These comments addressed legal and technical issues in addition to providing a preliminary estimated cost of complying with the proposed guidelines utilizing one of the EPA's compliance scenarios. Costs associated with this proposal could be significant to the utility industry and the Southern Company system. However, the ultimate financial and operational impact of the proposed Clean Power Plan on the Southern Company system cannot be determined at this time and will depend upon numerous known and unknown factors. Some of the unknown factors include: the structure, timing, and content of the EPA's final guidelines; individual state

implementation of these guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

Over the past several years, the U.S. Congress has also considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2013 greenhouse gas emissions were approximately 40.8 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2014 greenhouse gas emissions on the same basis is approximately 40 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.

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 under "Nuclear Outage Accounting Order" 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

Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate 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 weighted cost of equity (WCE) range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.

On December 1, 2014, the Company submitted the required annual filing under Rate RSE to the Alabama PSC. The Rate RSE increase was 3.49%, or $181 million annually, effective January 1, 2015. The revenue adjustment includes the performance based adder of 0.07%. Under the terms of Rate RSE, the maximum increase for 2016 cannot exceed 4.51%.

Rate CNP

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 4, 2014, 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, 2014 through March 31, 2015. It is anticipated that no adjustment will be made to Rate CNP PPA in 2015.

The Company has elected the normal purchase normal sale (NPNS) scope exception under the derivative accounting rules for its two wind PPAs, which total approximately 400 MWs. The NPNS exception allows the PPAs to be recorded at a cost, rather than fair value, basis. The industry's application of the NPNS exception to certain physical forward transactions in nodal markets was previously under review by the SEC at the request of the electric utility industry. In June 2014, the SEC requested the Financial Accounting Standards Board to address the issue through the Emerging Issues Task Force (EITF). Any accounting decisions will now be subject to EITF deliberations. The outcome of the EITF's deliberations cannot be determined at this time. If the Company is ultimately required to record these PPAs at fair value, an offsetting regulatory asset or regulatory liability will be recorded.

Rate CNP Environmental allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. Rate CNP Environmental is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. The Rate CNP Environmental increase effective January 1, 2015 was 1.5%, or $75 million annually, based upon projected billings.

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 2014, the Alabama PSC issued a consent order that the Company leave in effect for 2015 the energy cost recovery rates which began in 2011. Therefore, the Rate ECR factor as of January 1, 2015 remained at 2.681 cents per KWH. Effective with billings beginning in January 2016, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

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 would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement. See "Environmental Matters – Environmental Statutes and Regulations" herein for additional information regarding environmental regulations.

As part of its environmental compliance strategy, the Company plans to retire Plant Gorgas Units 6 and 7. These units represent 200 MWs of the Company's approximately 12,200 MWs of generating capacity. The Company also plans to cease 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. Additionally, the Company expects to cease using coal at Plant Barry Unit 3 (225 MWs) and Plant Greene County Units 1 and 2 (300 MWs) and begin operating those units solely on natural gas. These plans are expected to be effective no later than April 2016.

In accordance with an accounting order from the Alabama PSC, the Company will transfer the unrecovered plant asset balances to a regulatory asset at their respective retirement dates. The regulatory asset will be amortized through Rate CNP Environmental over the remaining useful lives, as established prior to the decision for retirement. As a result, these decisions will not have a significant impact on the Company's financial statements.

Cost of Removal Accounting Order

In accordance with an accounting order issued on November 3, 2014 by the Alabama PSC, at December 31, 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 account balances amortized 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 August 2013, respectively. Approximately $95 million of non-nuclear outage costs and $28 million of compliance and pension costs were fully amortized at December 31, 2014.

The cost of removal accounting order also required the Company to terminate, as of December 31, 2014, the regulatory asset accounts created pursuant to the compliance and pension cost accounting order and the non-nuclear outage accounting order. Consequently, the Company will not defer any expenditures in 2015, 2016, and 2017 related to critical electric infrastructure and domestic nuclear facilities, as allowed under the previous orders.

Non-Environmental Federal Mandated Costs Accounting Order

On December 9, 2014, pending the development of a new cost recovery mechanism, the Alabama PSC issued an accounting order authorizing the deferral as a regulatory asset of up to $50 million of costs associated with non-environmental federal mandates that would otherwise impact rates in 2015.

On February 17, 2015, the Company filed a proposed modification to Rate CNP Environmental with the Alabama PSC to include compliance costs for both environmental and non-environmental mandates. The non-environmental costs that would be recovered through the revised mechanism concern laws, regulations, and other mandates directed at the utility industry involving the security, reliability, safety, sustainability, or similar considerations impacting the Company's facilities or operations. If approved as requested, the effective date for the revised mechanism would be March 20, 2015, upon which the regulatory asset balance would be reclassified to the under recovered balance for Rate CNP Environmental, and the related customer rates would not become effective before January 2016. The ultimate outcome of this matter cannot be determined at this time.

Income Tax Matters

Bonus Depreciation

On December 19, 2014, the Tax Increase Prevention Act of 2014 (TIPA) was signed into law. The TIPA retroactively extended several tax credits through 2014 and extended 50% bonus depreciation for property placed in service in 2014 (and for certain long-term production-period projects to be placed in service in 2015). The extension of 50% bonus depreciation had a positive impact on the Company's cash flows and, combined with bonus depreciation allowed in 2014 under the American Taxpayer Relief Act of 2012, resulted in approximately $165 million of positive cash flows for the 2014 tax year. The estimated cash flow benefit of bonus depreciation related to TIPA is expected to be approximately $65 million to $70 million for the 2015 tax year.

Other Matters

In accordance with accounting standards related to employers' accounting for pensions, the Company recorded pension costs of $23 million in 2014, $47 million in 2013 and $6 million in 2012. Postretirement benefit costs for the Company were $4 million, $7 million, and $10 million in 2014, 2013, and 2012, respectively. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension and postretirement benefit costs is capitalized based on construction-related labor charges. Pension and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

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

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

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

The Company is subject to retail regulation by the 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 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.

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, in accordance with GAAP, 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 financial position, results of operations, or cash flows.

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 in accordance with GAAP 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 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. The Company discounts the future cash flows related to its postretirement benefit plans 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 purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $156 million and $22 million, respectively. The adoption of new mortality tables will increase net periodic costs related to the Company's pension plans and other postretirement benefit plans in 2015 by $20 million and $2 million, respectively.

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 $113 million or less change in projected obligations.

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2014. 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 comply with environmental regulations and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2015 through 2017, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to maintain existing generation facilities, to add environmental equipment for existing generating units, to add or change fuel sources for certain existing units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances. 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, 2014 as compared to December 31, 2013. No contributions to the qualified pension plan were made for the year ended December 31, 2014. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. The Company's funding obligations for the nuclear decommissioning trust fund are based on the 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 $1.7 billion for 2014, a decrease of $205 million as compared to 2013. The decrease in cash provided from operating activities was primarily due to an increase in income tax payments and the timing of fossil fuel stock purchases, partially offset by the timing of payment of accounts payable. Net cash provided from operating activities totaled $1.9 billion for 2013, an increase of $538 million as compared to 2012. The increase in cash provided from operating activities was primarily due to changes in timing of fossil fuel stock purchases and payment of accounts payable, and collection of fuel cost recovery revenues.

Net cash used for investing activities totaled $1.6 billion for 2014, $1.1 billion for 2013, and $0.9 billion for 2012. In 2014, these additions were primarily due to gross property additions related to environmental, distribution, transmission, steam generation, and nuclear fuel. In 2013, these additions were primarily due to gross property additions related to steam generation, distribution, and transmission equipment. In 2012, these additions were primarily due to gross property additions related to nuclear fuel and transmission, distribution, and steam generating equipment.

Net cash used for financing activities totaled $164 million in 2014 primarily due to the payment of common stock dividends, and issuances and redemptions of securities. Net cash used for financing activities totaled $614 million in 2013 primarily due to the payment of common stock dividends, and the issuance and a maturity of senior notes. 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 2014 included an increase of $854 million in property, plant, and equipment primarily due to additions to environmental, distribution, transmission, and steam generation. Other significant changes included increases of $454 million in securities due within one year and $418 million in other regulatory assets, deferred related to pension and other postretirement benefits.

The Company's ratio of common equity to total capitalization, including short-term debt, was 45.6% in 2014 and 44.3% in 2013. 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. The Company has primarily utilized funds from operating cash flows, short-term debt, 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.

The Company's current liabilities sometimes exceed current assets because of the Company's debt due within one year and the periodic use of short-term debt as a funding source primarily to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business.

At December 31, 2014, the Company had approximately $273 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2014 were as follows:

Expires[a]					Executable Term-Loans		Due Within One Year	
2015	2016	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
				(in millions)				
$ 228	$ 50	$ 1,030	$ 1,308	$ 1,308	$ 58	$ —	$ 58	$ 170

(a) No credit arrangements expire in 2017.

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 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 specified threshold. The Company is currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings. The Company expects to renew its bank credit arrangements as needed, prior to expiration.

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. As of December 31, 2014, the Company had $784 million of outstanding variable rate pollution control revenue bonds requiring liquidity support. In addition, at December 31, 2014, the Company had $280 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

In addition, the Company 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 operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each company under these arrangements are several and there is no cross-affiliate credit support.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2014:					
Commercial paper	$—	—%	$13	0.2%	$300
December 31, 2013:					
Commercial paper	$—	—%	$11	0.2%	$90
December 31, 2012:					
Commercial paper	$—	—%	$6	0.2%	$57

(a) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2014, 2013, and 2012.

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

Financing Activities

In August 2014, the Company issued $400 million aggregate principal amount of Series 2014A 4.150% Senior Notes due August 15, 2044. The proceeds were used for general corporate purposes, including the Company's continuous construction program.

During 2014, the Company entered into forward-starting interest rate swaps to hedge exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $200 million.

In December 2014, the Company incurred obligations related to the issuance of $254 million of The Industrial Development Board of the Town of Columbia, Pollution Control Revenue Refunding Bonds (Alabama Power Company Project), Series 2014 – A, 2014 – B, 2014 – C, and 2014 – D due December 1, 2037. The proceeds were used to refund, in December 2014, approximately $254 million of The Industrial Development Board of the Town of Columbia, Pollution Control Revenue Refunding Bonds (Alabama Power Company Project), Series 1995 – A, 1995 – B, 1995 – C, 1995 – D, 1995 – E, 1996 – A, 1999 – A, 1999 – B, and 1999 – C.

Subsequent to December 31, 2014, the Company announced the redemption of $250 million aggregate principal amount of its Series DD 5.65% Senior Notes due March 15, 2035, which will occur on March 16, 2015.

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 to below BBB- and/or Baa3. These contracts are primarily for physical electricity purchases, fuel purchases, fuel transportation and storage, and energy price risk management. At December 31, 2014, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $365 million. Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash.

Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

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 enters into derivatives that have been designated as hedges. The weighted average interest rate on $984 million of long-term variable interest rate exposure at January 1, 2015 was 0.71%. 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 $10 million at January 1, 2015. 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, 2014 when compared to the year ended December 31, 2013.

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:

	2014 Changes	2013 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$ (1)	$ (13)
Contracts realized or settled	(7)	10
Current period changes[a]	(44)	2
Contracts outstanding at the end of the period, assets (liabilities), net	$ (52)	$ (1)

(a) 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:

	2014	2013
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	54	64
Commodity – Natural gas options	2	5
Total hedge volume	56	69

The weighted average swap contract cost above market prices was approximately $0.89 per mmBtu as of December 31, 2014 and $0.02 per mmBtu as of December 31, 2013. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. The majority of the natural gas hedge gains and losses are recovered through the Company's retail energy cost recovery clause.

At December 31, 2014 and 2013, 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. 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, 2014 were as follows:

	Fair Value Measurements December 31, 2014		
	Total Fair Value	Maturity	
		Year 1	Years 2&3
		(in millions)	
Level 1	$ —	$ —	$ —
Level 2	(52)	(31)	(21)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (52)	$ (31)	$ (21)

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 Company's construction program consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. Over the next three years, the Company estimates spending, as part of its base level capital investment, $515 million on Plant Farley (including nuclear fuel), $892 million on distribution facilities, and $556 million on transmission additions. These base level capital investment amounts also include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Costs related to proposed water and final CCR rules are not included in the construction program base level capital investment. In addition, these estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information. The Company's base level construction program investments including investments to comply with existing environmental statutes and regulations and the estimated incremental compliance costs related to the proposed water and final CCR rules over the 2015 through 2017 three-year period, based on the final CCR rule which will continue to regulate CCR as non-hazardous solid waste, are estimated as follows:

	2015	2016	2017
Construction program:		*(in millions)*	
Base capital	$ 1,114	$ 857	$ 1,092
Existing environmental statutes and regulations	417	171	53
Total construction program base level capital investment	$ 1,531	$ 1,028	$ 1,145
Estimated incremental environmental compliance investments:			
Proposed water and final CCR rules	$ 4	$ 88	$ 239

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" 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 the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in the expected environmental compliance program; changes in FERC rules and regulations; 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.

At December 31, 2014, in addition to the funds required for the Company's construction program, approximately $454 million will be required by the end of 2015 for maturities of long-term debt. Subsequent to December 31, 2014, the Company announced the redemption of $250 million aggregate principal amount of its Series DD 5.65% Senior Notes due March 15, 2035 that will occur on March 16, 2015, which increased the total funds required for maturities of long-term debt by the end of 2015 to $704 million. 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.

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, 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

	2015	2016-2017	2018-2019	After 2019	Total
			(in millions)		
Long-term debt[a] —					
Principal	$ 454	$ 761	$ 200	$ 5,216	$ 6,631
Interest	259	503	435	3,436	4,633
Preferred and preference stock dividends[b]	39	79	79	—	197
Financial derivative obligations[c]	40	21	—	—	61
Operating leases[d]	16	24	11	17	68
Capital Lease	—	1	1	3	5
Purchase commitments —					
Capital[e]	1,343	2,281	—	—	3,624
Fuel[f]	1,297	1,705	867	529	4,398
Purchased power[g]	68	144	156	854	1,222
Other[h]	45	81	81	365	572
Pension and other postretirement benefit plans[i]	18	33	—	—	51
Total	$ 3,579	$ 5,633	$ 1,830	$ 10,420	$ 21,462

(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, 2015, 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 three-year period, including capital expenditures and compliance costs associated with existing environmental regulations. Such amounts exclude the Company's estimates of potential incremental environmental compliance investment to comply with proposed water and final CCR rules, which are approximately $4 million, $88 million, and $239 million for 2015, 2016, and 2017, respectively. These amounts also exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements, which are reflected separately. At December 31, 2014, 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, 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, 2014.

(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 2014 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, filings with state and federal regulatory authorities, impact of the TIPA, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, CCR, and emissions of sulfur, nitrogen, CO_2, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters, pending EPA civil action against the Company, and IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any operational and 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, or 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 currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional 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.

[This page intentionally left blank]

STATEMENTS OF INCOME
For the Years Ended December 31, 2014, 2013, and 2012
Alabama Power Company 2014 Annual Report

	2014	2013	2012
		(in millions)	
Operating Revenues:			
Retail revenues	$ 5,249	$ 4,952	$ 4,933
Wholesale revenues, non-affiliates	281	248	277
Wholesale revenues, affiliates	189	212	111
Other revenues	223	206	199
Total operating revenues	5,942	5,618	5,520
Operating Expenses:			
Fuel	1,605	1,631	1,503
Purchased power, non-affiliates	185	100	73
Purchased power, affiliates	200	129	182
Other operations and maintenance	1,468	1,289	1,287
Depreciation and amortization	603	645	639
Taxes other than income taxes	356	348	340
Total operating expenses	4,417	4,142	4,024
Operating Income	1,525	1,476	1,496
Other Income and (Expense):			
Allowance for equity funds used during construction	49	32	19
Interest income	15	16	16
Interest expense, net of amounts capitalized	(255)	(259)	(287)
Other income (expense), net	(22)	(36)	(24)
Total other income and (expense)	(213)	(247)	(276)
Earnings Before Income Taxes	1,312	1,229	1,220
Income taxes	512	478	477
Net Income	800	751	743
Dividends on Preferred and Preference Stock	39	39	39
Net Income After Dividends on Preferred and Preference Stock	$ 761	$ 712	$ 704

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2014, 2013, and 2012
Alabama Power Company 2014 Annual Report

	2014	2013	2012
		(in millions)	
Net Income	**$ 800**	$ 751	$ 743
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(3), $-, and $(7), respectively	**(5)**	—	(11)
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $1, respectively	**2**	1	2
Total other comprehensive income (loss)	**(3)**	1	(9)
Comprehensive Income	**$ 797**	$ 752	$ 734

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2014, 2013, and 2012
Alabama Power Company 2014 Annual Report

	2014	2013	2012
		(in millions)	
Operating Activities:			
Net income	$ 800	$ 751	$ 743
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	724	816	767
Deferred income taxes	270	198	164
Allowance for equity funds used during construction	(49)	(32)	(19)
Pension, postretirement, and other employee benefits	(61)	9	(21)
Stock based compensation expense	11	10	9
Other, net	17	(38)	(24)
Changes in certain current assets and liabilities —			
-Receivables	(58)	2	23
-Fossil fuel stock	61	146	(132)
-Materials and supplies	(17)	19	(21)
-Other current assets	(11)	5	(4)
-Accounts payable	157	35	(77)
-Accrued taxes	(199)	(23)	(12)
-Accrued compensation	50	(23)	(3)
-Retail fuel cost over recovery	5	42	1
-Other current liabilities	9	(3)	(18)
Net cash provided from operating activities	1,709	1,914	1,376
Investing Activities:			
Property additions	(1,457)	(1,107)	(867)
Nuclear decommissioning trust fund purchases	(245)	(280)	(194)
Nuclear decommissioning trust fund sales	244	279	193
Cost of removal net of salvage	(77)	(47)	(33)
Change in construction payables	(10)	(13)	12
Other investing activities	(22)	26	(45)
Net cash used for investing activities	(1,567)	(1,142)	(934)
Financing Activities:			
Proceeds —			
Capital contributions from parent company	28	24	27
Pollution control bonds	254	—	—
Senior notes issuances	400	300	1,000
Redemptions —			
Pollution control revenue bonds	(254)	—	(1)
Senior notes	—	(250)	(950)
Payment of preferred and preference stock dividends	(39)	(39)	(39)
Payment of common stock dividends	(550)	(644)	(684)
Other financing activities	(3)	(5)	(2)
Net cash used for financing activities	(164)	(614)	(649)
Net Change in Cash and Cash Equivalents	(22)	158	(207)
Cash and Cash Equivalents at Beginning of Year	295	137	344
Cash and Cash Equivalents at End of Year	$ 273	$ 295	$ 137
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $18, $11 and $7 capitalized, respectively)	$ 231	$ 243	$ 273
Income taxes (net of refunds)	436	296	309
Noncash transactions — accrued property additions at year-end	8	18	31

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

BALANCE SHEETS
At December 31, 2014 and 2013
Alabama Power Company 2014 Annual Report

Assets	2014	2013
		(in millions)
Current Assets:		
Cash and cash equivalents	$ 273	$ 295
Receivables —		
Customer accounts receivable	345	341
Unbilled revenues	138	142
Under recovered regulatory clause revenues	74	—
Other accounts and notes receivable	23	30
Affiliated companies	37	54
Accumulated provision for uncollectible accounts	(9)	(8)
Fossil fuel stock, at average cost	268	329
Materials and supplies, at average cost	406	375
Vacation pay	65	63
Prepaid expenses	244	57
Other regulatory assets, current	84	54
Other current assets	5	6
Total current assets	1,953	1,738
Property, Plant, and Equipment:		
In service	23,080	22,092
Less accumulated provision for depreciation	8,522	8,114
Plant in service, net of depreciation	14,558	13,978
Nuclear fuel, at amortized cost	348	332
Construction work in progress	1,006	748
Total property, plant, and equipment	15,912	15,058
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	66	54
Nuclear decommissioning trusts, at fair value	756	714
Miscellaneous property and investments	84	80
Total other property and investments	906	848
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	525	519
Prepaid pension costs	—	276
Deferred under recovered regulatory clause revenues	31	25
Other regulatory assets, deferred	1,063	645
Other deferred charges and assets	162	142
Total deferred charges and other assets	1,781	1,607
Total Assets	$ 20,552	$ 19,251

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

BALANCE SHEETS
At December 31, 2014 and 2013
Alabama Power Company 2014 Annual Report

Liabilities and Stockholder's Equity	2014	2013
		(in millions)
Current Liabilities:		
Securities due within one year	$ 454	$ —
Accounts payable —		
Affiliated	248	198
Other	443	339
Customer deposits	87	85
Accrued taxes —		
Accrued income taxes	2	11
Other accrued taxes	37	33
Accrued interest	66	61
Accrued vacation pay	54	53
Accrued compensation	131	74
Other regulatory liabilities, current	2	37
Other current liabilities	80	41
Total current liabilities	1,604	932
Long-Term Debt (See accompanying statements)	6,176	6,233
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	3,874	3,603
Deferred credits related to income taxes	72	75
Accumulated deferred investment tax credits	125	133
Employee benefit obligations	326	195
Asset retirement obligations	829	730
Other cost of removal obligations	744	828
Other regulatory liabilities, deferred	239	259
Deferred over recovered regulatory clause revenues	47	15
Other deferred credits and liabilities	79	61
Total deferred credits and other liabilities	6,335	5,899
Total Liabilities	14,115	13,064
Redeemable Preferred Stock (See accompanying statements)	342	342
Preference Stock (See accompanying statements)	343	343
Common Stockholder's Equity (See accompanying statements)	5,752	5,502
Total Liabilities and Stockholder's Equity	$ 20,552	$ 19,251
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2014 and 2013
Alabama Power Company 2014 Annual Report

	2014	2013	2014	2013
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term debt payable to affiliated trusts —				
Variable rate (3.36% at 1/1/15) due 2042	$ **206**	$ 206		
Long-term notes payable —				
0.55% due 2015	**400**	400		
5.20% due 2016	**200**	200		
5.50% to 5.55% due 2017	**525**	525		
5.13% due 2019	**200**	200		
3.375% to 6.125% due 2020-2044	**3,950**	3,550		
Total long-term notes payable	**5,275**	4,875		
Other long-term debt —				
Pollution control revenue bonds —				
0.28% to 5.00% due 2034	**367**	367		
Variable rate (0.03% at 1/1/15) due 2015	**54**	54		
Variable rates (0.04% to 0.06% at 1/1/15) due 2017	**36**	36		
Variable rates (0.01% to 0.06% at 1/1/15) due 2021-2038	**694**	694		
Total other long-term debt	**1,151**	1,151		
Capitalized lease obligations	**5**	5		
Unamortized debt discount, net	**(7)**	(4)		
Total long-term debt (annual interest requirement — $259 million)	**6,630**	6,233		
Less amount due within one year	**454**	—		
Long-term debt excluding amount due within one year	**6,176**	6,233	**49.0%**	50.2%
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 — 5.20% to 5.83%				
Authorized — 27,500,000 shares				
Outstanding — 12,000,000 shares: $25 stated value				
(annual dividend requirement — $18 million)	**294**	294		
Total redeemable preferred stock	**342**	342	**2.7**	2.7
Preference Stock:				
Authorized — 40,000,000 shares				
Outstanding — $1 par value — 5.63% to 6.50%				
— 14,000,000 shares (noncumulative): $25 stated value				
(annual dividend requirement — $21 million)	**343**	343	**2.7**	2.8
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	**2,304**	2,262		
Retained earnings	**2,255**	2,044		
Accumulated other comprehensive loss	**(29)**	(26)		
Total common stockholder's equity	**5,752**	5,502	**45.6**	44.3
Total Capitalization	$ **12,613**	$ 12,420	**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, 2014, 2013, and 2012
Alabama Power Company 2014 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, 2011	31	$ 1,222	$ 2,182	$ 1,956	$ (18)	$ 5,342
Net income after dividends on preferred and preference stock	—	—	—	704	—	704
Capital contributions from parent company	—	—	45	—	—	45
Other comprehensive income (loss)	—	—	—	—	(9)	(9)
Cash dividends on common stock	—	—	—	(684)	—	(684)
Balance at December 31, 2012	31	1,222	2,227	1,976	(27)	5,398
Net income after dividends on preferred and preference stock	—	—	—	712	—	712
Capital contributions from parent company	—	—	35	—	—	35
Other comprehensive income (loss)	—	—	—	—	1	1
Cash dividends on common stock	—	—	—	(644)	—	(644)
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**

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

[This page intentionally left blank]

Index to the Notes to Financial Statements

Note		Page
1	Summary of Significant Accounting Polices	II-156
2	Retirement Benefits	II-163
3	Contingencies and Regulatory Matters	II-174
4	Joint Ownership Agreements	II-178
5	Income Taxes	II-179
6	Financing	II-182
7	Commitments	II-184
8	Stock Compensation	II-186
9	Nuclear Insurance	II-187
10	Fair Value Measurements	II-187
11	Derivatives	II-191
12	Quarterly Financial Information (Unaudited)	II-195

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Alabama Power Company (the Company) is a wholly owned subsidiary of The Southern Company (Southern Company), which is the parent company of four traditional operating companies, Southern Power, SCS, SouthernLINC Wireless, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, and other direct and indirect subsidiaries. The traditional operating companies – the Company, Georgia Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity 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. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants, including the Company's Plant Farley.

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. The Company follows GAAP in the U.S. and complies 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

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

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 $400 million, $340 million, and $340 million during 2014, 2013, and 2012, 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 $234 million, $211 million, and $218 million during 2014, 2013, and 2012, 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 were $13 million in 2014, $13 million in 2013, and $12 million in 2012. Also, Mississippi Power reimburses the Company for any direct fuel purchases delivered from one of the Company's transfer facilities, which were $34 million in 2014, $27 million in 2013, and $28 million in 2012. See Note 4 for additional information.

The Company has an agreement with Gulf Power under which the Company has made transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA. In 2009, Gulf Power entered into a PPA for the capacity and energy from a combined cycle plant located in Autauga County, Alabama. The total cost committed by the Company related to the upgrades is approximately $85 million, of which approximately $29 million was spent in 2014. The transmission improvements were

completed in 2014. The Company expects to recover a majority of these costs through a tariff with Gulf Power until 2023. The remainder of these costs will be recovered through normal rate mechanisms.

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 2014, 2013, or 2012.

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

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

Regulatory Assets and Liabilities

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

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

	2014	2013	Note
	(in millions)		
Deferred income tax charges	$ 525	$ 519	(a,k)
Loss on reacquired debt	80	86	(b)
Vacation pay	65	63	(c,j)
Under/(over) recovered regulatory clause revenues	57	(18)	(d)
Fuel-hedging losses	53	8	(e)
Other regulatory assets	49	52	(f)
Asset retirement obligations	(125)	(132)	(a)
Other cost of removal obligations	(744)	(828)	(a)
Deferred income tax credits	(72)	(75)	(a)
Fuel-hedging gains	(1)	(8)	(e)
Nuclear outage	56	51	(d)
Natural disaster reserve	(84)	(96)	(h)
Other regulatory liabilities	(8)	(11)	(d,g)
Retiree benefit plans	882	461	(i,j)
Regulatory deferrals	13	20	(l)
Nuclear fuel disposal fee	(8)	—	(m)
Total regulatory assets (liabilities), net	$ 738	$ 92	

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 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.

(e) 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 energy cost recovery clause.

(f) Comprised of components including generation site selection/evaluation costs, PPA capacity, 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 other liabilities. 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 $18 million for 2014 and $20 million for 2013 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 of five years.

(m) Recorded as approved by the Alabama PSC related to potential future fees for nuclear waste disposal. The term of deferral is conditional upon resolution by the DOE. See Note 3 for additional information.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any

impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

Revenues

Wholesale capacity revenues 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 continuously monitors the under/over recovered balances and 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" 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 and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel.

See Note 3 under "Retail Regulatory Matters – Nuclear Waste Fund Fee Accounting Order" for additional information.

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.

In accordance with accounting standards related to the uncertainty in income taxes, 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:

	2014	2013
	(in millions)	
Generation	$ 11,670	$ 11,314
Transmission	3,579	3,287
Distribution	6,196	5,934
General	1,623	1,545
Plant acquisition adjustment	12	12
Total plant in service	$ 23,080	$ 22,092

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 3.3% in 2014 and 3.2% in 2013 and 2012. Depreciation studies are conducted periodically to update the composite rates and the information is provided to the Alabama PSC and 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 2014, the Company submitted a depreciation study to the FERC and received authorization to use the recommended rates beginning January 2015. The study was also provided to the Alabama PSC.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) are computed as the present value of the 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. 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. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, asbestos removal, 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 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:

	2014	2013
	(in millions)	
Balance at beginning of year	$ 730	$ 589
Liabilities incurred	1	—
Liabilities settled	(3)	(1)
Accretion	45	40
Cash flow revisions	56	102
Balance at end of year	$ 829	$ 730

The cash flow revisions in 2014 are primarily related to the Company's AROs associated with asbestos at its steam generation facilities. The cash flow revisions in 2013 are primarily related to revisions to the nuclear decommissioning ARO based on the Company's updated decommissioning study.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in landfills and surface impoundments at active generating power plants. The ultimate

impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $311 million and ongoing post-closure care of approximately $49 million. The Company will record AROs for the estimated closure costs required under the CCR Rule during 2015. SEGCO, which is jointly owned with Georgia Power, will also record an ARO for ash ponds commonly used at Plant E.C. Gaston. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Nuclear Decommissioning

The NRC requires licensees of commercial nuelear 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, 2014, investment securities in the Funds totaled $754 million, consisting of equity securities of $583 million, debt securities of $163 million, and $8 million of other securities. At December 31, 2013, investment securities in the Funds totaled $713 million, consisting of equity securities of $566 million, debt securities of $131 million, and $16 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 $244 million, $279 million, and $193 million in 2014, 2013, and 2012, respectively, all of which were reinvested. For 2014, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $54 million, of which $2 million related to realized gains and $19 million related to unrealized gains related to securities held in the Funds at December 31, 2014. For 2013, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $120 million, of which $5 million related to realized gains and $85 million related to unrealized gains related to securities held in the Funds at December 31, 2013. For 2012, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $70 million, of which $4 million related to realized gains and $50 million related to unrealized losses related to securities held in the Funds at December 31, 2012. 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 over periods 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:

	2014	2013
	(in millions)	
External trust funds	$ 754	$ 713
Internal reserves	21	21
Total	$ 775	734

Site study costs is the estimate to decommission a facility as of the site study year. The estimated costs of decommissioning as of December 31, 2014 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

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. All current construction costs are included in retail rates. The AFUDC composite rate as of December 31 was 8.8% in 2014, 9.1% in 2013, and 9.4% in 2012. AFUDC, net of income taxes, as a percent of net income after dividends on preferred and preference stock was 7.9% in 2014, 5.4% in 2013, and 3.3% in 2012.

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 charged 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 (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 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. If any, immaterial 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. See Note 11 for additional information regarding derivatives.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2014.

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). No contributions were made to the qualified pension plan during 2014. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. 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, 2015, other postretirement trusts contributions are expected to total approximately $2 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2011 for the 2012 plan year using discount rates for the pension plans and the other postretirement benefit plans of 4.98% and 4.88%, respectively, and an annual salary increase of 3.84%.

	2014	2013	2012
Discount rate:			
Pension plans	**4.18%**	5.02%	4.27%
Other postretirement benefit plans	**4.04**	4.86	4.06
Annual salary increase	**3.59**	3.59	3.59
Long-term return on plan assets:			
Pension plans	**8.20**	8.20	8.20
Other postretirement benefit plans	**7.34**	7.36	7.19

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

For purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $156 million and $22 million, respectively.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2014 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	9.00%	4.50%	2024
Post-65 medical	6.00	4.50	2024
Post-65 prescription	6.75	4.50	2024

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, 2014 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 34	$ (29)
Service and interest costs	1	(1)

Pension Plans

The total accumulated benefit obligation for the pension plans was $2.4 billion at December 31, 2014 and $1.9 billion at December 31, 2013. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 2,112	$ 2,218
Service cost	48	52
Interest cost	103	93
Benefits paid	(100)	(93)
Actuarial (gain) loss	429	(158)
Balance at end of year	2,592	2,112
Change in plan assets		
Fair value of plan assets at beginning of year	2,278	2,077
Actual return on plan assets	207	285
Employer contributions	11	9
Benefits paid	(100)	(93)
Fair value of plan assets at end of year	2,396	2,278
Prepaid pension costs (accrued liability)	$ (196)	$ 166

At December 31, 2014, the projected benefit obligations for the qualified and non-qualified pension plans were $2.5 billion and $123 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's pension plans consist of the following:

	2014	2013
	(in millions)	
Prepaid pension costs	$ —	$ 276
Other regulatory assets, deferred	827	476
Other current liabilities	(10)	(9)
Employee benefit obligations	(186)	(101)

Presented below are the amounts included in regulatory assets at December 31, 2014 and 2013 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 2015.

	2014	2013	Estimated Amortization in 2015
		(in millions)	
Prior service cost	$ 12	$ 19	$ 6
Net (gain) loss	815	457	55
Regulatory assets	$ 827	$ 476	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in millions)	
Regulatory assets:		
Beginning balance	**$ 476**	$ 822
Net (gain) loss	**389**	(287)
Reclassification adjustments:		
Amortization of prior service costs	**(7)**	(7)
Amortization of net gain (loss)	**(31)**	(52)
Total reclassification adjustments	**(38)**	(59)
Total change	**351**	(346)
Ending balance	**$ 827**	$ 476

Components of net periodic pension cost were as follows:

	2014	2013	2012
		(in millions)	
Service cost	**$ 48**	$ 52	$ 44
Interest cost	**103**	93	94
Expected return on plan assets	**(168)**	(157)	(162)
Recognized net (gain) loss	**31**	52	23
Net amortization	**7**	7	7
Net periodic pension cost	**$ 21**	$ 47	$ 6

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, 2014, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2015	$ 127
2016	114
2017	120
2018	125
2019	129
2020 to 2024	708

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 431	$ 490
Service cost	5	6
Interest cost	20	19
Benefits paid	(27)	(24)
Actuarial (gain) loss	71	(62)
Retiree drug subsidy	3	2
Balance at end of year	503	431
Change in plan assets		
Fair value of plan assets at beginning of year	389	343
Actual return on plan assets	23	61
Employer contributions	4	7
Benefits paid	(24)	(22)
Fair value of plan assets at end of year	392	389
Accrued liability	$ (111)	$ (42)

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's other postretirement benefit plans consist of the following:

	2014	2013
	(in millions)	
Other regulatory assets, deferred	$ 68	$ 6
Other regulatory liabilities, deferred	(14)	(21)
Employee benefit obligations	(111)	(42)

Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2014 and 2013 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 2015.

	2014	2013	Estimated Amortization in 2015
		(in millions)	
Prior service cost	$ 15	$ 19	$ 4
Net (gain) loss	39	(34)	2
Net regulatory assets (liabilities)	$ 54	$ (15)	

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in millions)	
Net regulatory assets (liabilities):		
Beginning balance	$ (15)	$ 89
Net gain (loss)	73	(99)
Reclassification adjustments:		
Amortization of prior service costs	(4)	(3)
Amortization of net gain (loss)	—	(2)
Total reclassification adjustments	(4)	(5)
Total change	69	(104)
Ending balance	$ 54	$ (15)

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

	2014	2013	2012
		(in millions)	
Service cost	$ 5	$ 6	$ 5
Interest cost	20	19	22
Expected return on plan assets	(25)	(23)	(23)
Net amortization	4	5	6
Net periodic postretirement benefit cost	$ 4	$ 7	$ 10

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)	
2015	$ 31	$ (3)	$ 28
2016	32	(3)	29
2017	32	(4)	28
2018	34	(4)	30
2019	34	(4)	30
2020 to 2024	172	(22)	150

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, 2014 and 2013, along with the targeted mix of assets for each plan, is presented below:

	Target	2014	2013
Pension plan assets:			
Domestic equity	26%	**30%**	31%
International equity	25	**23**	25
Fixed income	23	**27**	23
Special situations	3	**1**	1
Real estate investments	14	**14**	14
Private equity	9	**5**	6
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	48%	**48%**	47%
International equity	20	**20**	20
Domestic fixed income	24	**26**	27
Special situations	1	**—**	—
Real estate investments	4	**4**	4
Private equity	3	**2**	2
Total	100%	**100%**	100%

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

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, 2014 and 2013. 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 and private equity.*** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

The fair values of pension plan assets as of December 31, 2014 and 2013 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2014:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Domestic equity*	$ 421	$ 174	$ —	$ 595
International equity*	264	244	—	508
Fixed income:				
U.S. Treasury, government, and agency bonds	—	173	—	173
Mortgage- and asset-backed securities	—	47	—	47
Corporate bonds	—	280	—	280
Pooled funds	—	127	—	127
Cash equivalents and other	1	163	—	164
Real estate investments	73	—	277	350
Private equity	—	—	141	141
Total	$ 759	$ 1,208	$ 418	$ 2,385

* 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, 2013:	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)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 374	$ 219	$ —	$ 593
International equity*	287	265	—	552
Fixed income:				
U.S. Treasury, government, and agency bonds	—	156	—	156
Mortgage- and asset-backed securities	—	41	—	41
Corporate bonds	—	255	—	255
Pooled funds	—	123	—	123
Cash equivalents and other	—	58	—	58
Real estate investments	68	—	261	329
Private equity	—	—	149	149
Total	$ 729	$ 1,117	$ 410	$ 2,256
Liabilities:				
Derivatives	$ —	$ (1)	$ —	$ (1)
Total	$ 729	$ 1,116	$ 410	$ 2,255

* 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.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2014 and 2013 were as follows:

	2014		2013	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in millions)		
Beginning balance	**$ 261**	**$ 149**	$ 220	$ 155
Actual return on investments:				
Related to investments held at year end	**6**	**5**	19	2
Related to investments sold during the year	**8**	**(4)**	8	13
Total return on investments	**14**	**1**	27	15
Purchases, sales, and settlements	**2**	**(9)**	14	(21)
Ending balance	**$ 277**	**$ 141**	$ 261	$ 149

The fair values of other postretirement benefit plan assets as of December 31, 2014 and 2013 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

As of December 31, 2014:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 76	$ 8	$ —	$ 84
International equity*	13	12	—	25
Fixed income:				
U.S. Treasury, government, and agency bonds	—	10	—	10
Mortgage- and asset-backed securities	—	2	—	2
Corporate bonds	—	14	—	14
Pooled funds	—	6	—	6
Cash equivalents and other	—	8	—	8
Trust-owned life insurance	—	217	—	217
Real estate investments	5	—	13	18
Private equity	—	—	7	7
Total	$ 94	$ 277	$ 20	$ 391

* 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, 2013:	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)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 67	$ 11	$ —	$ 78
International equity*	14	13	—	27
Fixed income:				
U.S. Treasury, government, and agency bonds	—	17	—	17
Mortgage- and asset-backed securities	—	2	—	2
Corporate bonds	—	12	—	12
Pooled funds	—	6	—	6
Cash equivalents and other	—	10	—	10
Trust-owned life insurance	—	211	—	211
Real estate investments	4	—	13	17
Private equity	—	—	7	7
Total	$ 85	$ 282	$ 20	$ 387

* 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.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2014 and 2013 were as follows:

	2014		2013	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in millions)		
Beginning balance	$ 13	$ 7	$ 11	$ 8
Actual return on investments:				
Related to investments held at year end	—	—	1	—
Related to investments sold during the year	—	—	—	—
Total return on investments	—	—	1	—
Purchases, sales, and settlements	—	—	1	(1)
Ending balance	$ 13	$ 7	$ 13	$ 7

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 2014, 2013, and 2012 were $21 million, $20 million, and $19 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

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against the Company alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by Mississippi Power. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. The case against the Company (including claims involving a unit co-owned by Mississippi Power) has been actively litigated in the U.S. District Court for the Northern District of Alabama, resulting in a settlement in 2006 of the alleged NSR violations at Plant Miller; voluntary dismissal of certain claims by the EPA; and a grant of summary judgment for the Company on all remaining claims and dismissal of the case with prejudice in 2011. In September 2013, the U.S. Court of Appeals for the Eleventh Circuit affirmed in part and reversed in part the 2011 judgment in favor of the Company, and the case has been transferred back to the U.S. District Court for the Northern District of Alabama for further proceedings.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

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 properties. 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.

As a result of the first lawsuit, the Company recovered approximately $17 million, representing the vast majority of the Company's direct costs of the expansion of spent nuclear fuel storage facilities at Plant Farley from 1998 through 2004. In 2012, the award was credited to cost of service for the benefit of customers.

On December 12, 2014, the Court of Federal Claims entered a judgment in favor of the Company in its second spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. The Company was awarded approximately $26 million. No amounts have been recognized in the financial statements as of December 31, 2014. The final outcome of this matter cannot be determined at this time; however, no material impact on the Company's net income is expected.

On March 4, 2014, the Company filed a third 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. 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, 2014 for any potential recoveries from the third 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.

Retail Regulatory Matters

Rate RSE

Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate 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 weighted cost of equity (WCE) range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range. Prior to 2014, retail rates remained unchanged when the retail ROE was projected to be between 13.0% and 14.5%.

During 2013, the Alabama PSC held public proceedings regarding the operation and utilization of Rate RSE. In August 2013, the Alabama PSC voted to issue a report on Rate RSE that found that the Company's Rate RSE mechanism continues to be just and reasonable to customers and the Company, but recommended the Company modify Rate RSE as follows:

- Eliminate the provision of Rate RSE establishing an allowed range of ROE.
- Eliminate the provision of Rate RSE limiting the Company's capital structure to an allowed equity ratio of 45%.
- Replace these two provisions with a provision that establishes rates based upon the WCE range of 5.75% to 6.21%, with an adjusting point of 5.98%. If calculated under the previous Rate RSE provisions, the resulting WCE would range from 5.85% to 6.53%, with an adjusting point of 6.19%.
- Provide 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.

Substantially all other provisions of Rate RSE were unchanged.

In August 2013, the Company filed its consent to these recommendations with the Alabama PSC. The changes became effective for calendar year 2014. In November 2013, the Company made its Rate RSE submission to the Alabama PSC of projected data

for calendar year 2014; projected earnings were within the specified WCE range and, therefore, retail rates under Rate RSE remained unchanged for 2014. In 2012 and 2013, retail rates under Rate RSE remained unchanged from 2011. Under the terms of Rate RSE, the maximum possible increase for 2015 is 5.00%.

On December 1, 2014, the Company submitted the required annual filing under Rate RSE to the Alabama PSC. The Rate RSE increase was 3.49%, or $181 million annually, effective January 1, 2015. The revenue adjustment includes the performance based adder of 0.07%. Under the terms of Rate RSE, the maximum increase for 2016 cannot exceed 4.51%.

Rate CNP

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 4, 2014, 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, 2014 through March 31, 2015. It is anticipated that no adjustment will be made to Rate CNP PPA in 2015. As of December 31, 2014, the Company had an under recovered certificated PPA balance of $56 million, of which $27 million is included in under recovered regulatory clause revenues and $29 million is included in deferred under recovered regulatory clause revenues in the balance sheet.

In 2011, the Alabama PSC approved and certificated a PPA of approximately 200 MWs of electricity from wind-powered generating facilities that became operational in 2012. In 2012, the Alabama PSC approved and certificated a second PPA of approximately 200 MWs of electricity from other wind-powered generating facilities which became operational in 2014. The terms of the PPAs permit the Company to use the energy and retire the associated environmental attributes in service of its customers or to sell the environmental attributes, separately or bundled with energy. The Company has elected the normal purchase normal sale (NPNS) scope exception under the derivative accounting rules for its two wind PPAs, which total approximately 400 MWs. The NPNS exception allows the PPAs to be recorded at a cost, rather than fair value, basis. The industry's application of the NPNS exception to certain physical forward transactions in nodal markets was previously under review by the SEC at the request of the electric utility industry. In June 2014, the SEC requested the Financial Accounting Standards Board to address the issue through the Emerging Issues Task Force (EITF). Any accounting decisions will now be subject to EITF deliberations. The outcome of the EITF's deliberations cannot be determined at this time. If the Company is ultimately required to record these PPAs at fair value, an offsetting regulatory asset or regulatory liability will be recorded.

Rate CNP Environmental allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. Rate CNP Environmental is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. There was no adjustment to Rate CNP Environmental in 2014. In August 2013, the Alabama PSC approved the Company's petition requesting a revision to Rate CNP Environmental that allows recovery of costs related to pre-2005 environmental assets previously being recovered through Rate RSE. The Rate CNP Environmental increase effective January 1, 2015 was 1.5%, or $75 million annually, based upon projected billings. As of December 31, 2014, the Company had an under recovered environmental clause balance of $49 million, of which $47 million is included in under recovered regulatory clause revenues and $2 million is included in deferred under recovered regulatory clause revenues in the balance sheet.

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 2014, the Alabama PSC issued a consent order that the Company leave in effect for 2015 the energy cost recovery rates which began in 2011. Therefore, the Rate ECR factor as of January 1, 2015 remained at 2.681 cents per KWH. Effective with billings beginning in January 2016, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

The Company's over recovered fuel costs at December 31, 2014 totaled $47 million as compared to over recovered fuel costs of $42 million at December 31, 2013. At December 31, 2014, $47 million is included in deferred over recovered regulatory clause revenues. These classifications are based on estimates, which include such factors as weather, generation availability, energy

demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery or return of fuel costs.

Rate NDR

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. 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.

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 would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement.

As part of its environmental compliance strategy, the Company plans to retire Plant Gorgas Units 6 and 7. These units represent 200 MWs of the Company's approximately 12,200 MWs of generating capacity. The Company also plans to cease 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. Additionally, the Company expects to cease using coal at Plant Barry Unit 3 (225 MWs) and Plant Greene County Units 1 and 2 (300 MWs) and begin operating those units solely on natural gas. These plans are expected to be effective no later than April 2016.

In accordance with an accounting order from the Alabama PSC, the Company will transfer the unrecovered plant asset balances to a regulatory asset at their respective retirement dates. The regulatory asset will be amortized through Rate CNP Environmental over the remaining useful lives, as established prior to the decision for retirement. As a result, these decisions will not have a significant impact on the Company's financial statements.

Nuclear Waste Fund Accounting Order

In November 2013, the U.S. District Court for the District of Columbia ordered the DOE to cease collecting spent fuel depositary fees from nuclear power plant operators until such time as the DOE either complies with the Nuclear Waste Policy Act of 1982 or until the U.S. Congress enacts an alternative waste management plan. In accordance with the court's order, the DOE submitted a proposal to the U.S. Congress to change the fee to zero. On March 18, 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied the DOE's request for rehearing of the November 2013 panel decision ordering that the DOE propose the nuclear waste fund fee be changed to zero. The DOE formally set the fee to zero effective May 16, 2014.

On August 5, 2014, the Alabama PSC issued an order to provide for the continued recovery from customers of amounts associated with the permanent disposal of nuclear waste from the operation of Plant Farley. In accordance with the order, effective May 16, 2014, the Company is authorized to recover from customers an amount equal to the prior fee and to record the amounts in a regulatory liability account (approximately $14 million annually). At December 31, 2014, the Company recorded an $8 million regulatory liability which is included in other regulatory liabilities deferred in the balance sheet. Upon the DOE meeting the requirements of the Nuclear Waste Policy Act of 1982 and a new spent fuel depositary fee being put in place, the accumulated balance in the regulatory liability account will be available for purposes of the associated cost responsibility. In the

event the balance is later determined to be more than needed, those amounts would be used for the benefit of customers, subject to the approval of the Alabama PSC. The ultimate outcome of this matter cannot be determined at this time.

Compliance and Pension Cost Accounting Order

In 2012, the Alabama PSC approved an accounting order to defer to a regulatory asset account certain compliance-related operations and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in operations expense related to pension cost for 2013. These deferred costs would have been amortized over a three-year period beginning in January 2015. The compliance related expenditures were related to (i) standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation, (ii) cyber security requirements issued by the NRC, and (iii) NRC guidance addressing the readiness at nuclear facilities within the U.S. for severe events.

On November 3, 2014, the Alabama PSC issued an accounting order authorizing the Company to fully amortize the balances in certain regulatory asset accounts, including the $28 million of compliance and pension costs accumulated at December 31, 2014. This amortization expense was offset by the amortization of the regulatory liability for other cost of removal obligations. See "Cost of Removal Accounting Order" herein for additional information. The cost of removal accounting order requires the Company to terminate, as of December 31, 2014, the regulatory asset accounts created pursuant to the compliance and pension cost accounting order. Consequently, the Company will not defer any expenditures in 2015, 2016, and 2017 related to critical electric infrastructure and domestic nuclear facilities under these orders.

Non-Nuclear Outage Accounting Order

In August 2013, the Alabama PSC approved an accounting order to defer to a regulatory asset account certain operations and maintenance expenses associated with planned outages at non-nuclear generation facilities in 2014 and to amortize those expenses over a three-year period beginning in 2015.

On November 3, 2014, the Alabama PSC issued an accounting order authorizing the Company to fully amortize the balances in certain regulatory asset accounts, including the $95 million of non-nuclear outage costs accumulated at December 31, 2014. This amortization expense was reflected in other operations and maintenance and was offset by the amortization of the regulatory liability for other cost of removal obligations. See "Cost of Removal Accounting Order" herein for additional information. The cost of removal accounting order requires the Company to terminate, as of December 31, 2014, the regulatory asset accounts created pursuant to the non-nuclear outage accounting order.

Cost of Removal Accounting Order

In accordance with an accounting order issued on November 3, 2014 by the Alabama PSC, at December 31, 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 account balances amortized 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, as discussed herein.

Non-Environmental Federal Mandated Costs Accounting Order

On December 9, 2014, pending the development of a new cost recovery mechanism, the Alabama PSC issued an accounting order authorizing the deferral as a regulatory asset of up to $50 million of costs associated with non-environmental federal mandates that would otherwise impact rates in 2015.

On February 17, 2015, the Company filed a proposed modification to Rate CNP Environmental with the Alabama PSC to include compliance costs for both environmental and non-environmental mandates. The non-environmental costs that would be recovered through the revised mechanism concern laws, regulations, and other mandates directed at the utility industry involving the security, reliability, safety, sustainability, or similar considerations impacting the Company's facilities or operations. If approved as requested, the effective date for the revised mechanism would be March 20, 2015, upon which the regulatory asset balance would be reclassified to the under recovered balance for Rate CNP Environmental, and the related customer rates would not become effective before January 2016. The ultimate outcome of this matter cannot be determined at this time.

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 $84

million in 2014, $88 million in 2013, and $109 million in 2012 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. The Company had guaranteed $50 million principal amount of unsecured senior notes issued by SEGCO for general corporate purposes, which matured on May 15, 2013. 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, 2014, the capitalization of SEGCO consisted of $106 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 $42 million. SEGCO paid dividends of $3 million in 2014, $7 million in 2013, and $14 million in 2012, of which one-half of each was paid to the Company. In addition, the Company recognizes 50% of SEGCO's net income.

SEGCO plans to add natural gas as the primary fuel source for 1,000 MWs of its generating capacity in 2015. A natural gas pipeline was constructed and will be placed in service in 2015. 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 the gas pipeline. The Company will own 14% of the pipeline with the remaining 86% owned by SEGCO. At December 31, 2014, the Company's portion of the construction work in progress associated with the pipeline is $15 million.

In addition to the Company's ownership of SEGCO and joint ownership of the natural gas pipeline, the Company's percentage ownership and investment in jointly-owned coal-fired generating plants at December 31, 2014 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)	$ 164	$ 96	$ 1
Plant Miller Units 1 and 2	1,320	91.84% (2)	1,512	561	14

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

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

The Company has contracted to operate and maintain the 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 combined state income tax returns for the States of Alabama, Georgia, and Mississippi. In addition, the Company files a separate company income tax return for the State of Tennessee. 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:

	2014	2013	2012
		(in millions)	
Federal —			
Current	$ 198	$ 243	$ 262
Deferred	225	160	137
	423	403	399
State —			
Current	44	36	51
Deferred	45	39	27
	89	75	78
Total	$ 512	$ 478	$ 477

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:

	2014	2013
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	$ 3,429	$ 3,187
Property basis differences	457	458
Premium on reacquired debt	30	33
Employee benefit obligations	215	209
Regulatory assets associated with employee benefit obligations	366	198
Asset retirement obligations	59	38
Regulatory assets associated with asset retirement obligations	285	265
Other	156	128
Total	4,997	4,516
Deferred tax assets —		
Federal effect of state deferred taxes	219	205
Unbilled fuel revenue	42	41
Storm reserve	27	32
Employee benefit obligations	400	231
Other comprehensive losses	19	18
Asset retirement obligations	344	303
Other	90	108
Total	1,141	938
Total deferred tax liabilities, net	3,856	3,578
Portion included in current assets/(liabilities), net	18	25
Accumulated deferred income taxes	$ 3,874	$ 3,603

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

At December 31, 2014, 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, 2014, the tax-related regulatory liabilities to be credited to customers were $72 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 in 2014, 2013 and 2012. At December 31, 2014, 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:

	2014	2013	2012
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**4.4**	4.0	4.1
Non-deductible book depreciation	**1.1**	1.0	0.9
Differences in prior years' deferred and current tax rates	**(0.1)**	(0.1)	(0.1)
AFUDC equity	**(1.3)**	(0.9)	(0.5)
Other	**(0.1)**	(0.1)	(0.3)
Effective income tax rate	**39.0%**	38.9%	39.1%

Unrecognized Tax Benefits

The Company had no unrecognized tax benefits during 2014. Changes in unrecognized tax benefits in prior years were as follows:

	2013	2012
	(in millions)	
Unrecognized tax benefits at beginning of year	$ 31	$ 32
Tax positions from current periods	—	5
Tax positions from prior periods	(31)	(4)
Reductions due to settlements	—	(2)
Balance at end of year	$ —	$ 31

The decrease in tax positions from prior periods for 2013 relates primarily to the tax accounting method change for repairs-generation assets, which did not impact the effective tax rate. See "Tax Method of Accounting for Repairs" herein for additional information.

These amounts are presented on a gross basis without considering the related federal or state income tax impact. 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.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 federal income tax return and has received a partial acceptance letter from the IRS; however, the IRS has not finalized its audit. 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 2010.

Tax Method of Accounting for Repairs

In 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. Additionally, in April 2013, the IRS issued Revenue Procedure 2013-24, which provides guidance for taxpayers related to the deductibility of repair costs associated with generation assets. Based on a review of the regulations, Southern Company incorporated provisions related to repair costs for generation

assets into its consolidated 2012 federal income tax return and reversed all related unrecognized tax positions. In September 2013, the IRS issued Treasury Decision 9636, "Guidance Regarding Deduction and Capitalization of Expenditures Related to Tangible Property," which are final tangible property regulations applicable to taxable years beginning on or after January 1, 2014. Southern Company continues to review this guidance; however, these regulations are not expected to have a material impact on the Company's financial statements.

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, 2014 and 2013, 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 each of December 31, 2014 and 2013, 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, 2014, the Company had $454 million of senior notes and pollution control revenue bonds due within one year. At December 31, 2013, the Company had no scheduled maturities of senior notes or pollution control revenue bonds due within one year.

Maturities of senior notes and pollution control revenue bonds through 2019 applicable to total long-term debt are as follows: $454 million in 2015; $200 million in 2016; $561 million in 2017; and $200 million in 2019. There are no scheduled maturities in 2018.

Subsequent to December 31, 2014, the Company announced the redemption of $250 million aggregate principal amount of its Series DD 5.65% Senior Notes due March 15, 2035 that will occur on March 16, 2015.

Pollution Control Revenue Bonds

Pollution control 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. In December 2014, the Company incurred obligations related to the issuance of $254 million of The Industrial Development Board of the Town of Columbia, Pollution Control Revenue Refunding Bonds (Alabama Power Company Project), Series 2014 – A, Series 2014 – B, Series 2014 – C, and Series 2014 – D due December 1, 2037. The proceeds were used to refund in December 2014 approximately $254 million of The Industrial Development Board of the Town of Columbia, Pollution Control Revenue Refunding Bonds (Alabama Power Company Project), Series 1995 – A, 1995 – B, 1995 – C, 1995 – D, 1995 – E, 1996 – A, 1999 – A, 1999 – B, and 1999 – C.

The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2014 and 2013 was $1.2 billion, respectively.

Senior Notes

In August 2014, the Company issued $400 million aggregate principal amount of Series 2014A 4.150% Senior Notes due August 15, 2044. The proceeds were used for general corporate purposes, including the Company's continuous construction program.

During 2014, the Company entered into forward-starting interest rate swaps to hedge exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $200 million.

At December 31, 2014 and 2013, the Company had $5.3 billion and $4.9 billion of senior notes outstanding, respectively. As of December 31, 2014, the Company did not have any outstanding secured debt.

Outstanding Classes of Capital 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.

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. Certain series of the Company's preference stock are 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 and the other series of preference stock are subject to redemption at a price equal to the stated capital. All series of the Company's preferred stock currently are subject to redemption at the option of the Company. 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
5.20% Class A Preferred Stock	$25	6,480,000	Stated Capital
5.30% Class A Preferred Stock	$25	4,000,000	Stated Capital
5.625% Preference Stock	$25	6,000,000	Stated Capital
6.450% Preference Stock	$25	6,000,000	*
6.500% Preference Stock	$25	2,000,000	*

* Prior to 10/01/2017: Stated Value Plus Make-Whole Premium; after 10/01/2017: Stated Capital

Dividend Restrictions

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

Assets Subject to Lien

During 2014, all outstanding pollution control revenue bonds pursuant to which the Company granted liens on certain property were redeemed. 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.

Bank Credit Arrangements

At December 31, 2014, committed credit arrangements with banks were as follows:

Expires[a]					Executable Term-Loans		Due Within One Year	
2015	2016	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
				(in millions)				
$ 228	$ 50	$1,030	$1,308	$ 1,308	$ 58	$ —	$ 58	$ 170

(a) No credit arrangements expire in 2017.

The Company expects to renew its bank credit agreements as needed, prior to expiration. 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.

Most of the Company's bank credit arrangements contain covenants that limit the Company's debt 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. Exceeding this debt level would result in a default under the credit arrangements. At December 31, 2014, the Company was in compliance with the debt limit covenants.

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support was $784 million as of December 31, 2014. In addition, at December 31, 2014, the Company had $280 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, 2014 and 2013, there was no short-term debt outstanding. At December 31, 2014, the Company had regulatory approval to have outstanding up to $2 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 2014, 2013, and 2012, the Company incurred fuel expense of $1.6 billion, $1.6 billion, and $1.5 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.

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 $37 million, $30 million, and $33 million for 2014, 2013, and 2012, respectively. Total estimated minimum long-term obligations at December 31, 2014 were as follows:

	Operating Lease PPAs
	(in millions)
2015	$ 37
2016	39
2017	40
2018	41
2019	43
2020 and thereafter	137
Total commitments	$ 337

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

Operating Leases

The Company has entered into rental agreements for coal railcars, vehicles, and other equipment with various terms and expiration dates. Total rent expense was $18 million in 2014, $21 million in 2013, and $24 million in 2012. Of these amounts, $14 million, $18 million, and $19 million for 2014, 2013, and 2012, respectively, relate to the railcar leases and are recoverable through the Company's Rate ECR. As of December 31, 2014, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Vehicles & Other	Total
		(in millions)	
2015	$ 13	$ 3	$ 16
2016	11	3	14
2017	7	3	10
2018	5	1	6
2019	5	—	5
2020 and thereafter	17	—	17
Total	$ 58	$ 10	$ 68

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 $5 million in 2015, $4 million in 2016, and $12 million in 2020 and thereafter. There are no obligations under these leases in 2017, 2018, and 2019. 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 November 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 Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2014, there were approximately 1,000 current and former employees of the Company participating in the stock option program. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. Stock options held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted stock options for 2,027,298 shares, 1,319,038 shares, and 1,099,315 shares, respectively. The weighted average grant-date fair value of stock options granted during 2014, 2013, and 2012, derived using the Black-Scholes stock option pricing model, was $2.20, $2.93, and $3.39, respectively.

For the years ended December 31, 2014, 2013, and 2012, total compensation cost for stock option awards recognized in income was $5 million, $4 million, and $4 million, respectively, with the related tax benefit also recognized in income of $2 million, $2 million, and $1 million, respectively. The compensation cost and tax benefits related to the grant of Southern Company stock options to the Company's employees and the exercise of stock options are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. No cash proceeds are received by the Company upon the exercise of stock options. As of December 31, 2014, there was $1 million of unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 15 months.

The total intrinsic value of options exercised during the years ended December 31, 2014, 2013, and 2012 was $21 million, $11 million, and $28 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $8 million, $4 million, and $11 million for the years ended December 31, 2014, 2013, and 2012, respectively. As of December 31, 2014, the aggregate intrinsic value for the options outstanding and options exercisable was $55 million and $37 million, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount. Performance share units held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted performance share units of 176,070, 141,355, and 131,820, respectively. The weighted average grant-date fair value of performance share units granted during 2014, 2013, and 2012, 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 $37.54, $40.50, and $41.99, respectively.

The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. For the years ended December 31, 2014, 2013, and 2012, total compensation cost for performance share units recognized in income was $5 million annually, with the related tax benefit of $2 million annually also recognized in income. The compensation cost and tax benefits related to the grant of Southern Company performance share units to the Company's

employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2014, there was $5 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 20 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 $13.6 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. On April 1, 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 current maximum annual assessments for the Company under the NEIL policies would be $50 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, 2014, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 1	$ —	$ 1
Nuclear decommissioning trusts:[a]				
Domestic equity	403	83	—	486
Foreign equity	34	63	—	97
U.S. Treasury and government agency securities	—	34	—	34
Corporate bonds	—	111	—	111
Mortgage and asset backed securities	—	18	—	18
Other	—	5	3	8
Cash equivalents	162	—	—	162
Total	$ 599	$ 315	$ 3	$ 917
Liabilities:				
Interest rate derivatives	$ —	$ 8	$ —	$ 8
Energy-related derivatives	—	53	—	53
Total	$ —	$ 61	$ —	$ 61

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

As of December 31, 2013, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2013:	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	$ —	$ 7	$ —	$ 7
Nuclear decommissioning trusts:[a]				
Domestic equity	392	74	—	466
Foreign equity	35	65	—	100
U.S. Treasury and government agency securities	—	24	—	24
Corporate bonds	—	89	—	89
Mortgage and asset backed securities	—	18	—	18
Other	—	13	3	16
Cash equivalents	236	—	—	236
Total	$ 663	$ 290	$ 3	$ 956
Liabilities:				
Energy-related derivatives	$ —	$ 8	$ —	$ 8

(a) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases.

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 financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally, implied volatility of interest rate options. See Note 11 for additional information on how these derivatives are used.

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' judgment, are also obtained when available.

Investments in private equity and real estate within the nuclear decommissioning trusts are generally classified as Level 3, as the underlying assets typically do not have observable inputs. The fund manager values these assets using various inputs and techniques depending on the nature of the underlying investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

As of December 31, 2014 and 2013, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2014:	*(in millions)*			
Nuclear decommissioning trusts:				
Equity – commingled funds	$ 63	None	Daily/Monthly	Daily/7 days
Trust – owned life insurance	115	None	Daily	15 days
Debt – commingled funds	15	None	Daily	5 days
Cash equivalents:				
Money market funds	162	None	Daily	Not applicable
As of December 31, 2013:				
Nuclear decommissioning trusts:				
Equity – commingled funds	$ 65	None	Daily/Monthly	Daily/7 days
Trust – owned life insurance	110	None	Daily	15 days
Cash equivalents:				
Money market funds	236	None	Daily	Not applicable

The nuclear decommissioning trusts include investments in TOLI. The taxable nuclear decommissioning trusts invest in the TOLI in order to minimize the impact of taxes on the portfolios and can draw on the value of the TOLI through death proceeds, loans against the cash surrender value, and/or the cash surrender value, subject to legal restrictions. The amounts reported in the table above reflect the fair value of investments the insurer has made in relation to the TOLI agreements. The nuclear decommissioning trusts do not own the underlying investments, but the fair value of the investments approximates the cash surrender value of the TOLI policies. The investments made by the insurer are in commingled funds. These commingled funds, along with other equity and debt commingled funds held in the nuclear decommissioning trusts, primarily include investments in domestic and international equity securities and predominantly high-quality fixed income securities. These fixed income securities may include U.S. Treasury and government agency fixed income securities, non-U.S. government and agency fixed income securities, domestic and foreign corporate fixed income securities, and mortgage and asset backed securities. The passively managed funds seek to replicate the performance of a related index. The actively managed funds seek to exceed the performance of a related index through security analysis and selection.

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2014 and 2013, 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:		
2014	**$ 6,631**	**$ 7,321**
2013	$ 6,228	$ 6,534

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.

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 gross 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 commodity fuel prices and prices of electricity. 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.

To mitigate residual risks relative to movements in electricity prices, the Company may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in 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 energy 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 and 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, 2014, the net volume of energy-related derivative contracts for natural gas positions for the Company, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

Net Purchased mmBtu	Longest Hedge Date	Longest Non-Hedge Date
(in millions)		
56	2017	—

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to revenue and fuel expense for the 12-month period ending December 31, 2015 are immaterial.

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, 2014, 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, 2014
	(in millions)				*(in millions)*
Cash Flow Hedges of Forecasted Debt					
	$200	3-month LIBOR	2.93%	October 2025	$ (8)

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2015 are $3 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2035.

Derivative Financial Statement Presentation and Amounts

At December 31, 2014 and 2013, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 1**	$ 5	Other current liabilities	**$ 32**	$ 3
	Other deferred charges and assets	**—**	2	Other deferred credits and liabilities	**21**	5
Total derivatives designated as hedging instruments for regulatory purposes		**$ 1**	$ 7		**$ 53**	$ 8
Derivatives designated as hedging instruments in cash flow hedges						
Interest rate derivatives:	Other current assets	**$ —**	$ —	Other current liabilities	**$ 8**	$ —
Total		**$ 1**	$ 7		**$ 61**	$ 8

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2014 and 2013.

The derivative contracts of the Company are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related and interest rate derivative contracts contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts at December 31, 2014 and 2013 are presented in the following tables. Interest rate derivatives presented in the tables above do not have amounts available for offset and are therefore excluded from the offsetting disclosure table below.

	Fair Value			
Assets	**2014**	2013	**Liabilities**	**2014**	2013
	(in millions)			*(in millions)*	
Energy-related derivatives presented in the Balance Sheet [a]	$ 1	$ 7	Energy-related derivatives presented in the Balance Sheet [a]	$ 53	$ 8
Gross amounts not offset in the Balance Sheet [b]	—	(5)	Gross amounts not offset in the Balance Sheet [b]	—	(5)
Net energy-related derivative assets	$ 1	$ 2	**Net energy-related derivative liabilities**	$ 53	$ 3

(a) The Company does not offset fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.
(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

At December 31, 2014 and 2013, the pre-tax effect of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets was as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	$ (32)	$ (3)	Other current liabilities	$ 1	$ 5
	Other regulatory assets, deferred	(21)	(5)	Other regulatory liabilities, deferred	—	2
Total energy-related derivative gains (losses)		$ (53)	$ (8)		$ 1	$ 7

For the years ended December 31, 2014, 2013, and 2012, 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	**2014**	2013	2012	**Statements of Income Location**	**2014**	2013	2012
	(in millions)				*(in millions)*		
Interest rate derivatives	$ (8)	$ —	$ (18)	Interest expense, net of amounts capitalized	$ (3)	$ (3)	$ (3)

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2014, 2013, and 2012, the pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was 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, 2014, the Company's collateral posted with its derivative counterparties was not material.

At December 31, 2014, the fair value of derivative liabilities with contingent features was $18 million. However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $54 million, and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

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

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

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2014 and 2013 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2014	**$ 1,508**	**$ 381**	**$ 187**
June 2014	**1,437**	**357**	**173**
September 2014	**1,669**	**520**	**282**
December 2014	**1,328**	**267**	**119**
March 2013	$ 1,308	$ 307	$ 141
June 2013	1,392	357	173
September 2013	1,604	500	258
December 2013	1,314	312	140

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

SELECTED FINANCIAL AND OPERATING DATA 2010-2014
Alabama Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in millions)	**$ 5,942**	$ 5,618	$ 5,520	$ 5,702	$ 5,976
Net Income After Dividends on Preferred and Preference Stock (in millions)	**$ 761**	$ 712	$ 704	$ 708	$ 707
Cash Dividends on Common Stock (in millions)	**$ 550**	$ 644	$ 684	$ 774	$ 586
Return on Average Common Equity (percent)	**13.52**	13.07	13.10	13.19	13.31
Total Assets (in millions)	**$ 20,552**	$ 19,251	$ 18,712	$ 18,477	$ 17,994
Gross Property Additions (in millions)	**$ 1,543**	$ 1,204	$ 940	$ 1,016	$ 956
Capitalization (in millions):					
Common stock equity	**$ 5,752**	$ 5,502	$ 5,398	$ 5,342	$ 5,393
Preference stock	**343**	343	343	343	343
Redeemable preferred stock	**342**	342	342	342	342
Long-term debt	**6,176**	6,233	5,929	5,632	5,987
Total (excluding amounts due within one year)	**$ 12,613**	$ 12,420	$ 12,012	$ 11,659	$ 12,065
Capitalization Ratios (percent):					
Common stock equity	**45.6**	44.3	44.9	45.8	44.7
Preference stock	**2.7**	2.8	2.9	2.9	2.9
Redeemable preferred stock	**2.7**	2.7	2.8	2.9	2.8
Long-term debt	**49.0**	50.2	49.4	48.4	49.6
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**1,247,061**	1,241,998	1,237,730	1,231,574	1,235,128
Commercial	**197,082**	196,209	196,177	196,270	197,336
Industrial	**6,032**	5,851	5,839	5,844	5,770
Other	**753**	751	748	746	782
Total	**1,450,928**	1,444,809	1,440,494	1,434,434	1,439,016
Employees (year-end)	**6,935**	6,896	6,778	6,632	6,552

SELECTED FINANCIAL AND OPERATING DATA 2010-2014 (continued)
Alabama Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in millions):					
Residential	$ 2,209	$ 2,079	$ 2,068	$ 2,144	$ 2,283
Commercial	1,533	1,477	1,491	1,495	1,535
Industrial	1,480	1,369	1,346	1,306	1,231
Other	27	27	28	27	27
Total retail	5,249	4,952	4,933	4,972	5,076
Wholesale — non-affiliates	281	248	277	287	465
Wholesale — affiliates	189	212	111	244	236
Total revenues from sales of electricity	5,719	5,412	5,321	5,503	5,777
Other revenues	223	206	199	199	199
Total	$ 5,942	$ 5,618	$ 5,520	$ 5,702	$ 5,976
Kilowatt-Hour Sales (in millions):					
Residential	18,726	17,920	17,612	18,650	20,417
Commercial	14,118	13,892	13,963	14,173	14,719
Industrial	23,799	22,904	22,158	21,666	20,622
Other	211	211	214	214	216
Total retail	56,854	54,927	53,947	54,703	55,974
Wholesale — non-affiliates	3,588	3,711	4,196	4,330	8,655
Wholesale — affiliates	6,713	7,672	4,279	7,211	6,074
Total	67,155	66,310	62,422	66,244	70,703
Average Revenue Per Kilowatt-Hour (cents):					
Residential	11.80	11.60	11.74	11.50	11.18
Commercial	10.86	10.63	10.68	10.55	10.43
Industrial	6.22	5.98	6.07	6.03	5.97
Total retail	9.23	9.02	9.14	9.09	9.07
Wholesale	4.56	4.04	4.58	4.60	4.76
Total sales	8.52	8.16	8.52	8.31	8.17
Residential Average Annual Kilowatt-Hour Use Per Customer	15,051	14,451	14,252	15,138	16,570
Residential Average Annual Revenue Per Customer	$ 1,775	$ 1,676	$ 1,674	$ 1,740	$ 1,853
Plant Nameplate Capacity Ratings (year-end) (megawatts)	12,222	12,222	12,222	12,222	12,222
Maximum Peak-Hour Demand (megawatts):					
Winter	11,761	9,347	10,285	11,553	11,349
Summer	11,054	10,692	11,096	11,500	11,488
Annual Load Factor (percent)	61.4	64.9	61.3	60.6	62.6
Plant Availability (percent)*:					
Fossil-steam	82.5	87.3	88.6	88.7	92.9
Nuclear	93.3	90.7	94.5	94.7	88.4
Source of Energy Supply (percent):					
Coal	49.0	50.0	48.2	52.5	56.6
Nuclear	20.7	20.3	22.6	20.8	17.7
Hydro	5.5	8.1	4.1	4.6	5.0
Gas	15.4	15.7	16.8	15.3	14.0
Purchased power —					
From non-affiliates	3.6	2.9	2.0	0.9	1.6
From affiliates	5.8	3.0	6.3	5.9	5.1
Total	100.0	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

[This page intentionally left blank]

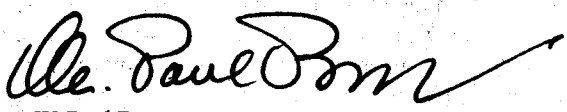
GEORGIA POWER COMPANY

FINANCIAL SECTION

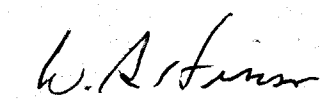
MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Georgia Power Company 2014 Annual Report

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, 2014.



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



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

March 2, 2015

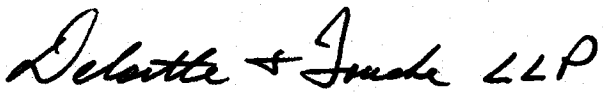
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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, 2014 and 2013, 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, 2014. 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-228 to II-277) present fairly, in all material respects, the financial position of Georgia Power Company as of December 31, 2014 and 2013, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.



Atlanta, Georgia
March 2, 2015

DEFINITIONS

Term	Meaning
2013 ARP	Alternative Rate Plan approved by the Georgia PSC for Georgia Power for the years 2014 through 2016
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ASC	Accounting Standards Codification
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
CWIP	Construction work in progress
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FFB	Federal Financing Bank
GAAP	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 operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
ROE	Return on equity
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
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 system	The Southern Company, the traditional operating companies, Southern Power, SEGCO, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional operating companies	Alabama Power, Georgia Power Company, Gulf Power, and Mississippi Power

OVERVIEW

Business Activities

Georgia Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area 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 selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, and fuel. In addition, the Company is currently constructing Plant Vogtle Units 3 and 4 and will own a 45.7% interest in these two nuclear generating units to increase its generation diversity and meet future supply needs. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

In December 2013, the Georgia PSC approved the 2013 ARP for the years 2014 through 2016 including a base rate increase of approximately $110 million for 2014 and required compliance filings for both 2015 and 2016 to review base rate increases for those respective years. On February 19, 2015, the Georgia PSC completed its review of the Company's October 3, 2014 compliance filing for 2015 and approved a base rate increase of approximately $136 million for that year. The 2016 base rate increase, which was approved in the 2013 ARP, will be determined through a compliance filing expected to be filed in late 2015, and will be subject to review by the Georgia PSC. The Company is scheduled to file its next base rate case by July 1, 2016. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate Plans" herein for additional information.

Key Performance Indicators

The Company continues to focus on several key performance indicators, including 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, which the Company achieved during 2014.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The Company's 2014 Peak Season EFOR of 1.93% was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages, with performance targets set based on historical performance. The Company's 2014 performance was better than the target for these transmission and distribution reliability measures.

The Company uses net income after dividends on preferred and preference stock as the primary measure of the Company's financial performance. In 2014, the Company achieved its targeted net income after dividends on preferred and preference stock. See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance.

Earnings

The Company's 2014 net income after dividends on preferred and preference stock was $1.2 billion, representing a $51 million, or 4.3%, increase over the previous year. The increase was due primarily to an increase in base retail revenues effective January 1, 2014 as authorized under the 2013 ARP and colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013, partially offset by higher non-fuel operations and maintenance expenses.

The Company's 2013 net income after dividends on preferred and preference stock was $1.2 billion, representing a $6 million, or 0.5%, increase over the previous year. The increase was due primarily to an increase related to retail revenue rate effects, partially offset by milder weather in 2013, an increase in depreciation and amortization, and higher income taxes.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2014	2014	2013
		(in millions)	
Operating revenues	$ 8,988	$ 714	$ 276
Fuel	2,547	240	256
Purchased power	988	104	(97)
Other operations and maintenance	1,902	248	10
Depreciation and amortization	846	39	62
Taxes other than income taxes	409	27	8
Total operating expenses	6,692	658	239
Operating income	2,296	56	37
Allowance for equity funds used during construction	45	15	(23)
Interest expense, net of amounts capitalized	348	(13)	(5)
Other income (expense), net	(22)	(27)	22
Income taxes	729	6	35
Net income	1,242	51	6
Dividends on preferred and preference stock	17	—	—
Net income after dividends on preferred and preference stock	$ 1,225	$ 51	$ 6

Operating Revenues

Operating revenues for 2014 were $9.0 billion, reflecting a $714 million increase from 2013. Details of operating revenues were as follows:

	Amount	
	2014	2013
	(in millions)	
Retail — prior year	$ 7,620	$ 7,362
Estimated change resulting from —		
Rates and pricing	183	137
Sales growth (decline)	21	(5)
Weather	139	(61)
Fuel cost recovery	277	187
Retail — current year	8,240	7,620
Wholesale revenues —		
Non-affiliates	335	281
Affiliates	42	20
Total wholesale revenues	377	301
Other operating revenues	371	353
Total operating revenues	$ 8,988	$ 8,274
Percent change	8.6%	3.5%

Retail base revenues of $5.2 billion in 2014 increased $343 million, or 7.1%, compared to 2013. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing was primarily due to base tariff increases effective January 1, 2014, as approved by the Georgia PSC in the 2013 ARP, and increases in collections for financing costs related to the

construction of Plant Vogtle Units 3 and 4 through the NCCR tariff as well as higher contributions from market-driven rates from commercial and industrial customers. In 2014, residential base revenues increased $163 million, or 7.6%, commercial base revenues increased $108 million, or 5.5%, and industrial base revenues increased $74 million, or 11.1%, compared to 2013.

Retail base revenues of $4.9 billion in 2013 increased $71 million, or 1.5%, compared to 2012. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing was primarily due to base tariff increases effective April 1, 2012 and January 1, 2013, as approved by the Georgia PSC, related to placing new generating units at Plant McDonough-Atkinson in service and collecting financing costs related to the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff, as well as higher contributions from market-driven rates from commercial and industrial customers. The increase was partially offset by milder weather in 2013 as compared to 2012. In 2013, residential base revenues decreased $3 million, or 0.1%, commercial base revenues increased $43 million, or 2.2%, and industrial base revenues increased $28 million, or 4.4%, compared to 2012. Residential usage continued to be impacted by economic uncertainty, modest economic growth, and energy efficiency efforts.

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:

	2014	2013	2012
		(in millions)	
Capacity and other	$ 164	$ 174	$ 177
Energy	171	107	104
Total non-affiliated	$ 335	$ 281	$ 281

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 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 other non-affiliated sales increased $54 million, or 19.2%, in 2014 and were flat in 2013 as compared to 2012. The increase in 2014 was primarily due to increased demand resulting from colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 and the lower cost of Company-owned generation compared to the market cost of available energy. The decrease in capacity revenues reflects the expiration of a wholesale contract in December 2013 and the removal of Plant Branch Unit 2 capacity from contracts following the unit's retirement in September 2013.

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 2014, wholesale revenues from sales to affiliates increased $22 million as compared to 2013 due to colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 and the lower cost of Company-owned generation. Wholesale revenues from sales to affiliated companies remained flat in 2013 as compared to 2012.

Other operating revenues increased $18 million, or 5.1%, in 2014 from the prior year primarily due to $7 million in transmission service revenues, $5 million of solar application fee revenues, and $5 million in outdoor lighting revenues. Other operating revenues increased $18 million, or 5.4%, in 2013 from the prior year primarily due to higher revenues from transmission, pole attachments, and outdoor lighting.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2014 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2014	2014	2013	2014	2013*
	(in billions)				
Residential	**27.1**	**6.5%**	(1.0)%	**0.5%**	0.1%
Commercial	**32.4**	**1.4**	(0.9)	**(0.2)**	(0.2)
Industrial	**23.6**	**2.0**	—	**1.5**	0.7
Other	**0.7**	**0.5**	(1.8)	**0.3**	(1.8)
Total retail	**83.8**	**3.2**	(0.7)	**0.5%**	0.1%
Wholesale					
Non-affiliates	**4.3**	**42.6**	3.3		
Affiliates	**1.1**	**125.4**	(17.4)		
Total wholesale	**5.4**	**54.2**	(0.2)		
Total energy sales	**89.2**	**5.3%**	(0.7)%		

* In the first quarter 2012, the Company began using new actual advanced meter data to compute unbilled revenues. The weather-adjusted KWH sales variances shown above reflect an adjustment to the estimated allocation of the Company's unbilled January 2012 KWH sales among customer classes that is consistent with the actual allocation in 2013. Without this adjustment, 2013 weather-adjusted residential KWH sales decreased 0.4% as compared to 2012 while 2013 weather-adjusted commercial KWH sales increased 0.2% as compared to 2012.

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 2014, KWH sales for residential and commercial customer classes increased compared to 2013 primarily due to colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 and customer growth, partially offset by decreased customer usage. Industrial sales increased in 2014 compared to 2013. Increased demand in the paper, textiles, and stone, clay, and glass sectors were the main contributors to the increase in industrial sales in 2014 compared to 2013. Weather adjusted commercial KWH sales decreased by 0.2% as a result of decreased customer usage, largely offset by customer growth. Weather adjusted residential KWH sales increased by 0.5% as a result of customer growth, largely offset by decreased customer usage. Household income, one of the primary drivers of residential customer usage, was flat in 2014.

In 2013, KWH sales for residential and commercial customer classes decreased compared to 2012 primarily due to milder weather in 2013. Industrial sales were flat in 2013 compared to 2012. Increased demand in the paper, textiles, and stone, clay, and glass sectors were the main contributors to the increase in weather-adjusted industrial sales in 2013 compared to 2012.

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

Fuel and Purchased Power Expenses

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

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

	2014	2013	2012
Total generation *(billions of KWHs)*	**69.9**	66.8	59.8
Total purchased power *(billions of KWHs)*	**23.1**	21.4	28.7
Sources of generation *(percent)* —			
Coal	**41**	35	39
Nuclear	**22**	23	27
Gas	**35**	39	33
Hydro	**2**	3	1
Cost of fuel, generated *(cents per net KWH)* —			
Coal	**4.52**	4.92	4.63
Nuclear	**0.90**	0.91	0.87
Gas	**3.67**	3.33	3.02
Average cost of fuel, generated *(cents per net KWH)*	**3.40**	3.32	3.07
Average cost of purchased power *(cents per net KWH)**	**5.20**	4.83	4.24

* 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 $3.5 billion in 2014, an increase of $344 million, or 10.8%, compared to 2013. The increase was primarily due to a $292 million increase in the volume of KWHs generated and purchased due to colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 driving higher customer demand and an increase of $84 million in the average cost of purchased power primarily due to higher natural gas prices, partially offset by a $32 million decrease in the average cost of fuel primarily due to lower coal prices.

Fuel and purchased power expenses were $3.2 billion in 2013, an increase of $159 million, or 5.2%, compared to 2012. The increase was primarily due to a $284 million increase in the average cost of fuel and purchased power primarily due to higher natural gas prices and a $185 million increase due to an increase in the volume of KWHs generated, partially offset by a $310 million decrease due to a decrease in the volume of KWHs purchased, as the cost of Company-owned generation was lower than the market cost of available energy.

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 $2.5 billion in 2014, an increase of $240 million, or 10.4%, compared to 2013. The increase was primarily due to an increase of 5.7% in the volume of KWHs generated as a result of colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 driving higher customer demand and a 2.4% increase in the average cost of fuel per KWH generated primarily due to higher natural gas prices, partially offset by lower coal prices. Fuel expense was $2.3 billion in 2013, an increase of $256 million, or 12.5%, compared to 2012. The increase was primarily due to a 9.9% increase in the volume of KWHs generated as a result of higher prices for purchased power and an 8.1% increase in the average cost of fuel per KWH generated for all types of fuel generation, partially offset by a 191.0% increase in the volume of KWHs generated by hydro facilities resulting from greater rainfall.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates was $287 million in 2014, an increase of $63 million, or 28.1%, compared to 2013. The increase was primarily due to a 6.1% increase in the average cost per KWH purchased primarily resulting from higher natural gas prices and a 22.0% increase in the volume of KWHs purchased to meet higher customer demand resulting from colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013. Purchased power expense from non-affiliates was $224 million in 2013, a decrease of $91 million, or 28.9%, compared to 2012. The decrease was primarily due to a 52.0% decrease in the volume of KWHs purchased as the cost of Company-owned generation was lower than the market cost of available energy, partially offset by an increase of 41.5% in the average cost per KWH purchased primarily due to higher fuel 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 service territory, and the availability of the Southern Company system's generation.

Purchased Power - Affiliates

Purchased power expense from affiliates was $701 million in 2014, an increase of $41 million, or 6.2%, compared to 2013. The increase was primarily due to an increase of 5.8% in the average cost per KWH purchased reflecting higher natural gas prices and a 5.6% increase in the volume of KWHs purchased to meet higher customer demand resulting from colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013. Purchased power expense from affiliates was $660 million in 2013, a decrease of $6 million, or 0.9%, compared to 2012. The decrease was primarily due to an 18.4% decrease in the volume of KWHs purchased as the Company's units generally dispatched at a lower cost than other Southern Company system resources, partially offset by a 12.6% increase in the average cost per KWH purchased reflecting higher fuel prices.

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 2014, other operations and maintenance expenses increased $248 million, or 15.0%, compared to 2013. The increase was primarily due to increases of $74 million in transmission and distribution overhead line maintenance expenses, $58 million in generation expense to meet higher demand, $52 million in scheduled outage-related costs, $35 million in customer assistance expenses related to customer incentive and demand-side management costs, and $11 million in the storm damage accrual as authorized in the 2013 ARP.

In 2013, other operations and maintenance expenses increased $10 million, or 0.6%, compared to 2012. The increase was primarily due to an increase of $33 million in pension and other employee benefit-related expenses and $13 million in transmission system load expense resulting from billing adjustments with integrated transmission system owners, partially offset by a decrease of $38 million in fossil generating expenses due to cost containment and outage timing to offset milder weather in 2013 as compared to 2012 and the effect of economic uncertainty.

Depreciation and Amortization

Depreciation and amortization increased $39 million, or 4.8%, in 2014 compared to 2013. The increase was primarily due to decreases of $36 million and $17 million in amortization of regulatory liabilities related to state income tax credits that was completed in December 2013 and other cost of removal obligations as authorized in the 2013 ARP, respectively, partially offset by a decrease of $14 million in depreciation and amortization also as authorized in the 2013 ARP.

Depreciation and amortization increased $62 million, or 8.3%, in 2013 compared to 2012. The increase was primarily due to an increase of $64 million in depreciation on additional plant in service due to the completion of Plant McDonough-Atkinson Units 5 and 6 in 2012 and depreciation and amortization resulting from certain coal unit retirement decisions (with respect to the portion of such units dedicated to wholesale service). The increase was partially offset by a net reduction in amortization primarily related to amortization of the regulatory liability previously established for state income tax credits, as authorized by the Georgia PSC.

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

Taxes Other Than Income Taxes

In 2014, taxes other than income taxes increased $27 million, or 7.1%, compared to 2013. The increase was primarily due to increases of $24 million in municipal franchise fees related to higher retail revenues and $9 million in payroll taxes, partially offset by a $6 million decrease in property taxes.

In 2013, taxes other than income taxes increased $8 million, or 2.1%, compared to 2012. The increase was primarily due to an increase in property taxes.

Allowance for Equity Funds Used During Construction

AFUDC equity increased $15 million, or 50.0%, in 2014 compared to the prior year primarily due to an increase in construction related to ongoing environmental and transmission projects. AFUDC equity decreased $23 million, or 43.4%, in 2013 compared to the prior year primarily due to the completion of Plant McDonough-Atkinson Units 5 and 6 in 2012.

Interest Expense, Net of Amounts Capitalized

In 2014, interest expense, net of amounts capitalized decreased $13 million, or 3.6%, from the prior year. The decrease was primarily due to a $40 million decrease in interest on long-term debt resulting from redemptions and refinancing of long-term debt at lower interest rates and a $4 million increase in interest capitalized as a result of increased construction activity, partially offset by a $32 million increase in interest on outstanding long-term debt borrowings from the FFB.

In 2013, interest expense, net of amounts capitalized decreased $5 million, or 1.4%, from the prior year. The decrease was primarily due to a $21 million decrease in interest on long-term debt as a result of refinancing activity, partially offset by an $8 million decrease in AFUDC debt primarily due to the completion of Plant McDonough Units 5 and 6 discussed previously and a $9 million increase resulting from the conclusion of certain state and federal income tax audits that reduced interest expense in 2012.

Other Income (Expense), net

In 2014, other income (expense), net decreased $27 million from the prior year primarily due to a $9 million increase in donations and an $8 million decrease in wholesale operating fee revenue. In 2013, other income (expense), net increased $22 million, or 129.4%, from the prior year primarily due to an $8 million increase in wholesale operating fee revenue and a $9 million decrease in donations.

Income Taxes

Income taxes increased $6 million, or 0.8%, in 2014 compared to the prior year primarily due to higher pre-tax earnings and an increase in non-deductible book depreciation, partially offset by the recognition of tax benefits related to emission allowances and state apportionment, an increase in non-taxable AFUDC equity, and state income tax credits.

Income taxes increased $35 million, or 5.1%, in 2013 compared to the prior year primarily due to a decrease in state income tax credits, higher pre-tax earnings, and a decrease in non-taxable AFUDC equity, partially offset by a decrease in non-deductible book depreciation.

See "Allowance for Funds Used During Construction Equity" herein for additional information.

Effects of Inflation

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

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within 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 – Electric Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and the completion and subsequent operation of ongoing construction projects, primarily Plant Vogtle Units 3 and 4. Future earnings in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, 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. Changes in regional and global economic conditions may impact sales for the Company, as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

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. 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.

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against the Company alleging violations of the New Source Review provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by Gulf Power. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. See Note 3 to the financial statements under "Environmental Matters – New Source Review Actions" for additional information. The ultimate outcome of these matters cannot be determined at this time.

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; 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 2014, the Company had invested approximately $4.7 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $0.4 billion, $0.3 billion, and $0.2 billion for 2014, 2013, and 2012, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $0.8 billion from 2015 through 2017, with annual totals of approximately $0.3 billion, $0.2 billion, and $0.2 billion for 2015, 2016, and 2017, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information.

The Company'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 and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time. See "Retail Regulatory Matters – Integrated Resource Plans" herein for additional information on planned unit retirements and fuel conversions.

Compliance with any new federal or state legislation or regulations relating to air quality, water, CCR, global climate change, 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. Since 1990, the Company has spent approximately $4.3 billion in reducing and monitoring emissions pursuant to the Clean Air

Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2012, the EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015 up to April 16, 2016 for affected units for which extensions have been granted. On November 25, 2014, the U.S. Supreme Court granted a petition for review of the final MATS rule.

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 more stringent eight-hour ozone NAAQS, which it began to implement in 2011. In 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone NAAQS. The only area within the Company's service territory designated as an ozone nonattainment area is a 15-county area within metropolitan Atlanta. On December 17, 2014, the EPA published a proposed rule to further reduce the current eight-hour ozone standard. The EPA is required by federal court order to complete this rulemaking by October 1, 2015. Finalization of a lower eight-hour ozone standard could result in the designation of new ozone nonattainment areas within the Company's service territory.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS and, with the exception of the Atlanta area, the EPA has officially redesignated former nonattainment areas within the service territory as attainment for these standards. A redesignation request for the Atlanta area is pending with the EPA. In 2012, the EPA issued a final rule that increases the stringency of the annual fine particulate matter standard. The EPA promulgated final designations for the 2012 annual standard on December 18, 2014, and no new nonattainment areas were designated within the Company's service territory. The EPA has, however, deferred designation decisions for certain areas in Georgia, so future nonattainment designations in these areas are possible.

Final revisions to the NAAQS for sulfur dioxide (SO_2), which established a new one-hour standard, became effective in 2010. No areas within the Company's service territory have been designated as nonattainment under this rule. However, the EPA has announced plans to make additional designation decisions for SO_2 in the future, which could result in nonattainment designations for areas within the Company's service territory. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

The Company's service territory is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I beginning in 2015 and Phase II beginning in 2017. In 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety, but on April 29, 2014, the U.S. Supreme Court overturned that decision and remanded the case back to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The U.S. Court of Appeals for the District of Columbia Circuit granted the EPA's motion to lift the stay of the rule, and the first phase of CSAPR took effect on January 1, 2015.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology to certain sources, including fossil fuel-fired generating facilities, built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter.

In 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units), during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

In February 2013, the EPA proposed a rule that would require certain states to revise 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). The EPA proposed to supplement the 2013 proposed rule on September 17, 2014, making it more stringent. The EPA has entered into a settlement agreement requiring it to finalize the proposed rule by May 22, 2015. The proposed rule would require states subject to the rule (including Georgia, Alabama, and Florida) to revise their SSM provisions within 18 months after issuance of the final 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. As part of this strategy, the Company has developed a compliance plan for the MATS rule which includes reliance on existing emission control technologies,

the construction of baghouses to provide an additional level of control on the emissions of mercury and particulates from certain generating units, the use of additives or other injection technology, the use of additional natural gas capability, and unit retirements. Additionally, certain transmission system upgrades are required. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, CSAPR, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. These regulations could result in significant additional 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.

In addition to the federal air quality laws described above, the Company is also subject to the requirements of the 2007 State of Georgia Multi-Pollutant Rule. The Multi-Pollutant Rule, as amended, is designed to reduce emissions of mercury, SO_2, and nitrogen oxide state-wide by requiring the installation of specified control technologies at certain coal-fired generating units by specific dates between December 31, 2008 and April 16, 2015. A companion rule requires a 95% reduction in SO_2 emissions from the controlled units on the same or similar timetable. Through December 31, 2014, the Company had installed the required controls on 14 of its coal-fired generating units with two additional projects to be completed before the unit-specific installation deadlines.

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 on October 14, 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

In June 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing revised technology-based limits for certain wastestreams from steam electric power plants and best management practices for CCR surface impoundments. The EPA has entered into a consent decree requiring it to finalize revisions to the steam electric effluent guidelines by September 30, 2015. The ultimate impact of the rule will also depend on the specific technology requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

On April 21, 2014, the EPA and the U.S. Army Corps of Engineers jointly published a proposed rule to revise the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs, which would significantly expand the scope of federal jurisdiction under the CWA. In addition, the rule as proposed could have significant impacts on economic development projects which could affect customer demand growth. The ultimate impact of the proposed rule will depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time. If finalized as proposed, 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.

These proposed and final water quality regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Coal Combustion Residuals

The Company currently manages CCR at onsite units consisting of landfills and surface impoundments (CCR Units) at 11 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.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate 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 mandate 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 mandated closure of a CCR Unit. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and

timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $390 million and ongoing post-closure care of approximately $62 million. The Company has previously recorded asset retirement obligations (ARO) associated with ash ponds of $500 million, or $458 million on a nominal dollar basis, based on existing state requirements. During 2015, the Company will record AROs for any incremental estimated closure costs resulting from acceleration in the timing of any currently planned closures and for differences between existing state requirements and the requirements of the CCR Rule. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

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 properties. 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 2014, the EPA published three sets of proposed standards that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. On January 8, 2014, the EPA published proposed standards for new units, and, on June 18, 2014, the EPA published proposed standards governing existing units, known as the Clean Power Plan, and separate standards governing CO_2 emissions from modified and reconstructed units. The EPA's proposed Clean Power Plan establishes guidelines for states to develop plans to address CO_2 emissions from existing fossil fuel-fired electric generating units. The EPA's proposed guidelines establish state-specific interim and final CO_2 emission rate goals to be achieved between 2020 and 2029 and 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. 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 Southern Company system filed comments on the EPA's proposed Clean Power Plan on December 1, 2014. These comments addressed legal and technical issues in addition to providing a preliminary estimated cost of complying with the proposed guidelines utilizing one of the EPA's compliance scenarios. Costs associated with this proposal could be significant to the utility industry and the Southern Company system. However, the ultimate financial and operational impact of the proposed Clean Power Plan on the Southern Company system cannot be determined at this time and will depend upon numerous known and unknown factors. Some of the unknown factors include: the structure, timing, and content of the EPA's final guidelines; individual state implementation of these guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

Over the past several years, the U.S. Congress has also considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2013 greenhouse gas emissions were approximately 33 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2014 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.

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

In December 2013, the Georgia PSC voted to approve the 2013 ARP. The 2013 ARP reflects the settlement agreement among the Company, the Georgia PSC's Public Interest Advocacy Staff, and 11 of the 13 intervenors, which was filed with the Georgia PSC in November 2013.

On January 1, 2014, in accordance with the 2013 ARP, the Company increased its tariffs as follows: (1) traditional base tariff rates by approximately $80 million; (2) ECCR tariff by approximately $25 million; (3) DSM tariffs by approximately $1 million; and (4) MFF tariff by approximately $4 million, for a total increase in base revenues of approximately $110 million.

On February 19, 2015, in accordance with the 2013 ARP, the Georgia PSC approved adjustments to traditional base, ECCR, DSM, and MFF tariffs effective January 1, 2015 as follows:

- Traditional base tariffs by approximately $107 million to cover additional capacity costs;
- ECCR tariff by approximately $23 million;
- DSM tariffs by approximately $3 million; and
- MFF tariff by approximately $3 million to reflect the adjustments above.

The sum of these adjustments resulted in a base revenue increase of approximately $136 million in 2015.

The 2016 base rate increase, which was approved in the 2013 ARP, will be determined through a compliance filing expected to be filed in late 2015, and will be subject to review by the Georgia PSC.

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. However, if at any time during the term of the 2013 ARP, the Company projects that its retail earnings will be below 10.00% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff that would be used to adjust the Company's earnings back to a 10.00% retail ROE. The Georgia PSC would have 90 days to rule on the Company's request. The ICR tariff will expire at the earlier of January 1, 2017 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, the Company may file a full rate case. In 2014, the Company's retail ROE exceeded 12.00%, and the Company expects to refund to retail customers approximately $13 million in 2015, subject to review and approval by the Georgia PSC.

Except as provided above, the Company will not file for a general base rate increase while the 2013 ARP is in effect. The Company is required to file a general rate case by July 1, 2016, in response to which the Georgia PSC would be expected to determine whether the 2013 ARP should be continued, modified, or discontinued.

Renewables Development

On May 20, 2014, the Georgia PSC approved the Company's application for the certification of two PPAs executed in April 2013 for the purchase of energy from two wind farms in Oklahoma with capacity totaling 250 MWs that will begin in 2016 and end in 2035.

On December 16, 2014, the Georgia PSC approved and certified ten PPAs that were executed in October 2014. These PPAs provide for the purchase of energy from 515 MWs of solar capacity as part of the Georgia Power Advanced Solar Initiative program, of which approximately 99 MWs is expected to be purchased from solar facilities owned by Southern Power. These PPAs are expected to commence in December 2015 and 2016 and have terms ranging from 20 to 30 years.

On October 23, 2014, the Georgia PSC approved the Company's request to build, own, and operate three 30-MW solar generation facilities at three U.S. Army bases by the end of 2016. In addition, on December 16, 2014, the Georgia PSC approved the Company's request to build, own, and operate a 30-MW solar generation facility at Kings Bay Naval facility by the end of 2016.

Integrated Resource Plans

See "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," "– Coal Combustion Residuals," and "– Global Climate Issues," and "Rate Plans" 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; the State of Georgia's Multi-

Pollutant Rule; 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.

In July 2013, the Georgia PSC approved the Company's latest triennial Integrated Resource Plan (2013 IRP) including the Company's request to decertify 16 coal- and oil-fired units totaling 2,093 MWs. Several factors, including the cost to comply with existing and future environmental regulations, recent and forecasted economic conditions, and lower natural gas prices, contributed to the decision to close these units.

Plant Branch Units 3 and 4 (1,016 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) will be decertified and retired by April 16, 2015, the compliance date of the MATS rule. The decertification date of Plant Branch Unit 1 (250 MWs) was extended from December 31, 2013 as specified in the final order in the 2011 Integrated Resource Plan Update (2011 IRP Update) to coincide with the decertification date of Plant Branch Units 3 and 4. The decertification and retirement of Plant Kraft Units 1 through 4 (316 MWs) were also approved and will be effective by April 16, 2016, based on a one-year extension of the MATS rule compliance date that was approved by the State of Georgia Environmental Protection Division in September 2013 to allow for necessary transmission system reliability improvements. In July 2013, the Georgia PSC approved the switch to natural gas as the primary fuel for Plant Yates Units 6 and 7. In September 2013, Plant Branch Unit 2 (319 MWs) was retired as approved by the Georgia PSC in the 2011 IRP Update in order to comply with the State of Georgia's Multi-Pollutant Rule.

In the 2013 ARP, the Georgia PSC approved the amortization of the CWIP balances related to environmental projects that will not be completed at Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 over nine years beginning in January 2014 and the amortization of any remaining net book values of Plant Branch Unit 2 from October 2013 to December 2022, Plant Branch Unit 1 from May 2015 to December 2020, Plant Branch Unit 3 from May 2015 to December 2023, and Plant Branch Unit 4 from May 2015 to December 2024. The Georgia PSC deferred a decision regarding the appropriate recovery period for the costs associated with unusable materials and supplies remaining at the retiring plants to the Company's next base rate case, which the Company expects to file in 2016 (2016 Rate Case). In the 2013 IRP, the Georgia PSC also deferred decisions regarding the recovery of any fuel related costs that could be incurred in connection with the retirement units to be addressed in future fuel cases.

On July 1, 2014, the Georgia PSC approved the Company's request to cancel the proposed biomass fuel conversion of Plant Mitchell Unit 3 (155 MWs) because it would not be cost effective for customers. The Company expects to request decertification of Plant Mitchell Unit 3 in connection with the triennial Integrated Resource Plan to be filed in 2016. The Company plans to continue to operate the unit as needed until the MATS rule becomes effective in April 2015.

The decertification of these units and fuel conversions are not expected to have a material impact on the Company's financial statements; however, the ultimate outcome depends on the Georgia PSC's order in the 2016 Rate Case and future fuel cases and cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Company continues to be allowed to adjust its fuel cost recovery rates prior to the next fuel case if the under or over recovered fuel balance exceeds $200 million. On January 20, 2015, the Georgia PSC approved the deferral of the Company's next fuel case filing until at least June 30, 2015.

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 (collectively, Vogtle Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc., a subsidiary of The Shaw Group Inc., which was acquired by Chicago Bridge & Iron Company N.V. (CB&I) (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 that is 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. The Contractor's liability to the Vogtle Owners for schedule and performance liquidated damages and warranty claims is subject to a cap. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which have not 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%.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and CB&I's The Shaw Group Inc., respectively. 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. The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay certain termination costs. 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 2009, the NRC issued an Early Site Permit and Limited Work Authorization which allowed limited work to begin on Plant Vogtle Units 3 and 4. The NRC certified the Westinghouse Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, in late 2011, and issued combined construction and operating licenses (COLs) in early 2012. Receipt of the COLs allowed full construction to begin. 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 are expected as construction proceeds.

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 increases to the NCCR tariff of approximately $223 million, $35 million, $50 million, and $60 million, effective January 1, 2011, 2012, 2013, and 2014, respectively. On December 16, 2014, the Georgia PSC approved an increase to the NCCR tariff of approximately $27 million effective January 1, 2015.

In 2012, the Vogtle Owners and the Contractor began negotiations regarding the costs associated with design changes to the DCD and the delays in the timing of approval of the DCD and issuance of the COLs, including the assertion by the Contractor that the Vogtle Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. Also in 2012, the Company and the other Vogtle Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Vogtle Owners are not responsible for these costs. In 2012, the Contractor also filed suit against the Company and the other Vogtle Owners in the U.S. District Court for the District of Columbia alleging the Vogtle Owners are responsible for these costs. In August 2013, the U.S. District Court for the District of Columbia dismissed the Contractor's suit, ruling that the proper venue is the U.S. District Court for the Southern District of Georgia. The Contractor appealed the decision to the U.S. Court of Appeals for the District of Columbia Circuit in September 2013. The portion of additional costs claimed by the Contractor in its initial complaint that would be attributable to the Company (based on the Company's ownership interest) is approximately $425 million (in 2008 dollars). The Contractor also asserted it is entitled to extensions of the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. On May 22, 2014, the Contractor filed an amended counterclaim to the suit pending in the U.S. District Court for the Southern District of Georgia alleging that (i) the design changes to the DCD imposed by the NRC delayed module production and the impacts to the Contractor are recoverable by the Contractor under the Vogtle 3 and 4 Agreement and (ii) the changes to the basemat rebar design required by the NRC caused additional costs and delays recoverable by the Contractor under the Vogtle 3 and 4 Agreement. The Contractor did not specify in its amended counterclaim the amounts relating to these new allegations; however, the Contractor has subsequently asserted related minimum damages (based on the Company's ownership interest) of $113 million. The Contractor may from time to time continue to assert that it is entitled to additional payments with respect to these allegations, any of which could be substantial. The Company has not agreed to the proposed cost or to any changes to the guaranteed substantial completion dates or that the Vogtle Owners have any responsibility for costs related to these issues. Litigation is ongoing and the Company intends to vigorously defend the positions of the Vogtle Owners. The Company also expects negotiations with the Contractor to continue with respect to cost and schedule during which negotiations the parties may reach a mutually acceptable compromise of their positions.

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. If the projected certified construction capital costs to be borne by the Company increase by 5% or the projected in-service dates are significantly extended, the Company is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. The Company's eighth VCM report filed in February 2013 requested an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 from $4.4 billion to $4.8 billion and to extend the estimated in-service dates to the fourth quarter 2017 and the fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively.

In September 2013, the Georgia PSC approved a stipulation (2013 Stipulation) entered into by 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 accordance with the Georgia Integrated Resource Planning Act, any costs incurred by the Company in excess of the certified amount will be included in rate base, provided the Company shows the costs to be reasonable and prudent. In addition, financing costs on any construction-related costs in excess of the certified amount likely would be subject to recovery through AFUDC instead of the NCCR tariff.

The Georgia PSC has approved eleven VCM reports covering the periods through June 30, 2014, including construction capital costs incurred, which through that date totaled $2.8 billion.

On January 29, 2015, the Company announced that it was notified by the Contractor of the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4, which would incrementally delay the previously disclosed estimated in-service dates by 18 months (from the fourth quarter of 2017 to the second quarter of 2019 for Unit 3 and from the fourth quarter of 2018 to the second quarter of 2020 for Unit 4). The Company has not agreed to any changes to the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. The Company does not believe that the Contractor's revised forecast reflects all efforts that may be possible to mitigate the Contractor's delay.

In addition, the Company believes that, pursuant to the Vogtle 3 and 4 Agreement, the Contractor is responsible for the Contractor's costs related to the Contractor's delay (including any related construction and mitigation costs, which could be material) and that the Vogtle Owners are entitled to recover liquidated damages for the Contractor's delay beyond the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. Consistent with the Contractor's position in the pending litigation described above, the Company expects the Contractor to contest any claims for liquidated damages and to assert that the Vogtle Owners are responsible for additional costs related to the Contractor's delay.

On February 27, 2015, the Company filed its twelfth VCM report with the Georgia PSC covering the period from July 1 through December 31, 2014, which requests approval for an additional $0.2 billion of construction capital costs incurred during that period and reflects the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4 as well as additional estimated owner-related costs of approximately $10 million per month expected to result from the Contractor's proposed 18-month delay, including property taxes, oversight costs, compliance costs, and other operational readiness costs. No Contractor costs related to the Contractor's proposed 18-month delay are included in the twelfth VCM report. Additionally, while the Company has not agreed to any change to the guaranteed substantial completion dates, the twelfth VCM report includes a requested amendment to the Plant Vogtle Units 3 and 4 certificate to reflect the Contractor's revised forecast, to include the estimated owner's costs associated with the proposed 18-month Contractor delay, and to increase the estimated total in-service capital cost of Plant Vogtle Units 3 and 4 to $5.0 billion.

The Company will continue to incur financing costs of approximately $30 million per month until Plant Vogtle Units 3 and 4 are placed in service. The twelfth VCM report estimates total associated financing costs during the construction period to be approximately $2.5 billion.

Processes are in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, 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 issues are expected to 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.

As construction continues, the risk remains that ongoing challenges with Contractor performance including additional challenges in its fabrication, assembly, delivery, and installation of the shield building and structural modules, delays in the receipt of the remaining permits necessary for the operation of Plant Vogtle Units 3 and 4, or other issues could arise and may further impact project schedule and cost. In addition, the IRS allocated production tax credits to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021.

Additional claims by the Contractor or the Company (on behalf of the Vogtle Owners) are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement, but also may be resolved through litigation.

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

Income Tax Matters

Bonus Depreciation

On December 19, 2014, the Tax Increase Prevention Act of 2014 (TIPA) was signed into law. The TIPA retroactively extended several tax credits through 2014 and extended 50% bonus depreciation for property placed in service in 2014 (and for certain long-term production-period projects to be placed in service in 2015). The extension of 50% bonus depreciation had a positive impact on the Company's cash flows and, combined with bonus depreciation allowed in 2014 under the American Taxpayer Relief Act of 2012, resulted in approximately $200 million of positive cash flows for the 2014 tax year. The estimated cash flow benefit of bonus depreciation related to TIPA is expected to be approximately $45 million to $50 million for the 2015 tax year.

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.

Electric 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 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.

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, in accordance with GAAP, 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 financial position, results of operations, or cash flows.

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 in accordance with GAAP 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 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. The Company discounts the future cash flows related to its postretirement benefit plans 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 purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $226 million and $46 million, respectively. The adoption of new mortality tables will increase net periodic costs related to the Company's pension plans and other postretirement benefit plans in 2015 by $30 million and $5 million, respectively.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in an $11 million or less change in total annual benefit expense and a $163 million or less change in projected obligations.

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2014. 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 comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2015 through 2017, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to build new generation facilities, including Plant Vogtle Units 3 and 4, to maintain existing generation facilities, to add environmental equipment for existing generating units, to add or change fuel sources for certain existing units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt issuances and capital contributions from Southern Company, as well as by accessing 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 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, 2014 as compared to December 31, 2013. On December 18, 2014, the Company voluntarily contributed $150 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. The Company funded approximately $2 million to its nuclear decommissioning trust funds in 2014. 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 2014, a decrease of $403 million from 2013, primarily due to fuel cost recovery and storm restoration costs, partially offset by higher retail operating revenues and lower fuel inventory additions. Net cash provided from operating activities totaled $2.8 billion in 2013, an increase of $471 million from 2012, primarily due to higher retail operating revenues, lower fuel inventory additions, and settlement of affiliated payables related to pension funding in 2012, partially offset by fuel cost recovery.

Net cash used for investing activities totaled $2.2 billion, $1.9 billion, and $2.0 billion in 2014, 2013, and 2012, 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 $163 million, $891 million, and $290 million for 2014, 2013, and 2012, respectively. The decrease in cash used in 2014 compared to 2013 was primarily due to borrowings from the FFB for construction of Plant Vogtle Units 3 and 4, partially offset by FFB loan issuance costs and a reduction in short-term debt. The increase in cash used in 2013 compared to 2012 was primarily due to lower net issuances of long-term debt in 2013, partially offset by an increase in net short-term borrowings. See "Financing Activities" herein for additional information. 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 2014 included an increase of $1.2 billion in total property, plant, and equipment due to gross property additions described above, an increase in other regulatory assets, deferred of $640 million, a decrease of $303 million in fossil fuel stock due to an increase in fuel generation, and an increase of $361 million in employee benefit obligations primarily as a result of changes in the actuarial assumptions. See Note 2 to the financial statements for additional information.

The Company's ratio of common equity to total capitalization, including short-term debt, was 50.4% in 2014 and 49.1% in 2013. See Note 6 to the financial statements for additional information.

Sources of Capital

Except as described below with respect to the DOE loan guarantees, 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, 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 approvals, prevailing market conditions, and other factors.

On February 20, 2014, the Company and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement), pursuant to which the DOE agreed to guarantee borrowings to be made by the Company under a multi-advance credit facility (FFB Credit Facility) among the Company, the DOE, and the FFB. 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 also are secured by a first priority lien on (i) the Company's 45.7% 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. Under the FFB Credit Facility, the Company may make term loan borrowings through the FFB. Proceeds of borrowings made under the FFB Credit Facility will 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). 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. 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.

Eligible Project Costs incurred through December 31, 2014 would allow for borrowings of up to $2.1 billion under the FFB Credit Facility. Through December 31, 2014, the Company had borrowed $1.2 billion under the FFB Credit Facility, leaving $0.9 billion of currently available borrowing ability.

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.

As of December 31, 2014, the Company's current liabilities exceeded current assets by $1.0 billion primarily due to long-term debt that is due in one year. The Company intends to utilize equity contributions from Southern Company and cash from operations, as well as commercial paper, lines of credit, bank notes, and securities issuances, as market conditions permit, to fund the Company's short-term capital needs. In 2015, the Company also expects to utilize borrowings through the FFB as the primary source of borrowed funds. 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, 2014, the Company had approximately $24 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2014 were as follows:

Expires[a]			
2016	2018	Total	Unused
	(in millions)		
$150	$1,600	$1,750	$1,736

(a) No credit arrangements expire in 2015 or 2017.

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 variable rate 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, 2014 was approximately $865 million. In addition, at December 31, 2014, the Company had $118 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months. As of December 31, 2014, $98 million of certain pollution control revenue bonds of the Company were reclassified to securities due within one year in anticipation of their redemption in connection with unit retirement decisions.

The Company's credit arrangements contain covenants that limit debt levels and contain 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 specified threshold. The Company is currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings. Subject to applicable market conditions, the Company expects to renew its credit arrangements, as needed, prior to expiration.

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

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
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%**	
December 31, 2013:					
Commercial paper	$ 647	0.2%	$ 166	0.2%	$702
Short-term bank debt	400	0.9%	96	0.9%	400
Total	$ 1,047	0.5%	$ 262	0.5%	
December 31, 2012:					
Commercial paper	$ —	—%	$ 78	0.2%	$517
Short-term bank debt	—	—%	116	1.2%	300
Total	$ —	—%	$ 194	0.8%	

(a) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2014, 2013, and 2012.

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

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.

Pollution Control Revenue Bonds

In June 2014, the Company redeemed $17 million aggregate principal amount of Development Authority of Bartow County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), Second Series 1998 and $19.5 million aggregate principal amount of Development Authority of Appling County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Hatch Project), Second Series 2001.

In July 2014, the Company reoffered to the public $40 million aggregate principal amount of Development Authority of Monroe County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), First Series 2009, which had been previously purchased and held by the Company since 2010.

DOE Loan Guarantee Borrowings

On February 20, 2014, the Company made initial borrowings under the FFB Credit Facility in an aggregate principal amount of $1.0 billion and on December 11, 2014, the Company made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $200 million. The interest rate applicable to $500 million of the initial advance under the FFB Credit Facility is 3.860% for an interest period that extends to 2044 and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to 2029 and is expected to be reset from time to time thereafter through 2044. The interest rate applicable to the $200 million advance in December 2014 is 3.002% for an interest period that extends to 2044. The final maturity date for all advances under the FFB Credit Facility is February 20, 2044. The proceeds of the borrowings in 2014 under the FFB Credit Facility were used to reimburse the Company for Eligible Project Costs relating to the construction of Plant Vogtle Units 3 and 4. 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.

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. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information.

Other

In February 2014, the Company repaid three four-month floating rate bank loans in an aggregate principal amount of $400 million. At December 31, 2014, the Company had no bank term loans outstanding.

In October 2014, the Company entered into interest rate swaps to hedge exposure to interest rate changes related to existing debt. The notional amount of the swaps totaled $900 million.

In November and December 2014, the Company entered into forward-starting interest rate swaps to hedge exposure to interest rate changes related to anticipated borrowings under the FFB Credit Facility in 2015. The notional amount of the swaps totaled $700 million.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, interest rate derivatives, and construction of new generation. The maximum potential collateral requirements under these contracts at December 31, 2014 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 85
Below BBB- and/or Baa3	1,332

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

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 $1.3 billion of long-term variable interest rate exposure at January 1, 2015 was 1.24%. 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 $13 million at January 1, 2015. 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, 2014 when compared to the December 31, 2013 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:

	2014 Changes	2013 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$ (16)	$ (34)
Contracts realized or settled:		
Swaps realized or settled	2	9
Options realized or settled	8	20
Current period changes[(a)]:		
Swaps	(1)	1
Options	(13)	(12)
Contracts outstanding at the end of the period, assets (liabilities), net	$ (20)	$ (16)

(a) 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:

	2014	2013
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	4	7
Commodity – Natural gas options	42	52
Total hedge volume	46	59

The weighted average swap contract cost above market prices was approximately $0.68 per mmBtu as of December 31, 2014 and $0.50 per mmBtu as of December 31, 2013. 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, 2014 and 2013, 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, which have a 24-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. 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, 2014 were as follows:

	Fair Value Measurements December 31, 2014		
	Total Fair Value	Maturity	
		Year 1	Years 2&3
		(in millions)	
Level 1	$ —	$ —	$ —
Level 2	(20)	(16)	(4)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (20)	$ (16)	$ (4)

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 be $2.4 billion for 2015, $2.4 billion for 2016, and $2.1 billion for 2017. Capital expenditures to comply with environmental statutes and regulations included in these estimated amounts are $0.3 billion, $0.2 billion, and $0.2 billion for 2015, 2016, and 2017, respectively. These amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units.

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" 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 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, 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

	2015	2016-2017	2018-2019	After 2019	Total
			(in millions)		
Long-term debt[a] —					
Principal	$ 1,148	$ 1,154	$ 750	$ 6,756	$ 9,808
Interest	342	634	557	5,128	6,661
Preferred and preference stock dividends[b]	17	35	35	—	87
Financial derivative obligations[c]	31	4	—	—	35
Operating leases[d]	25	36	15	14	90
Capital leases[d]	6	13	15	6	40
Purchase commitments —					
Capital[e]	2,165	4,150	—	—	6,315
Fuel[f]	1,805	2,176	1,371	8,722	14,074
Purchased power[g]	293	684	606	3,545	5,128
Other[h]	92	124	101	272	589
Trusts —					
Nuclear decommissioning[i]	5	11	11	110	137
Pension and other postretirement benefit plans[j]	44	82	—	—	126
Total	$ 5,973	$ 9,103	$ 3,461	$ 24,553	$ 43,090

(a) All amounts are reflected based on final maturity dates. The Company plans to continue 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, 2015, 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 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) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs 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 separately. At December 31, 2014, 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.

(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, 2014.

(g) Estimated minimum long-term obligations for various PPA purchases from gas-fired, biomass, and wind-powered facilities. A total of $1.1 billion of biomass PPAs is contingent upon the counterparties meeting specified contract dates for commercial operation and may change as a result of regulatory action. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Renewables Development" 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 2014 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, completion dates of construction projects, filings with state and federal regulatory authorities, impact of the TIPA, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, CCR, and emissions of sulfur, nitrogen, CO_2, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including pending EPA civil action against the Company and IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction 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 Georgia PSC);
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any operational and environmental performance standards, including any PSC requirements 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 and related legal proceedings involving the commercial parties;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, or 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 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 at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

[This page intentionally left blank]

STATEMENTS OF INCOME
For the Years Ended December 31, 2014, 2013, and 2012
Georgia Power Company 2014 Annual Report

	2014	2013	2012
		(in millions)	
Operating Revenues:			
Retail revenues	$ 8,240	$ 7,620	$ 7,362
Wholesale revenues, non-affiliates	335	281	281
Wholesale revenues, affiliates	42	20	20
Other revenues	371	353	335
Total operating revenues	8,988	8,274	7,998
Operating Expenses:			
Fuel	2,547	2,307	2,051
Purchased power, non-affiliates	287	224	315
Purchased power, affiliates	701	660	666
Other operations and maintenance	1,902	1,654	1,644
Depreciation and amortization	846	807	745
Taxes other than income taxes	409	382	374
Total operating expenses	6,692	6,034	5,795
Operating Income	2,296	2,240	2,203
Other Income and (Expense):			
Allowance for equity funds used during construction	45	30	53
Interest expense, net of amounts capitalized	(348)	(361)	(366)
Other income (expense), net	(22)	5	(17)
Total other income and (expense)	(325)	(326)	(330)
Earnings Before Income Taxes	1,971	1,914	1,873
Income taxes	729	723	688
Net Income	1,242	1,191	1,185
Dividends on Preferred and Preference Stock	17	17	17
Net Income After Dividends on Preferred and Preference Stock	$ 1,225	$ 1,174	$ 1,168

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2014, 2013, and 2012
Georgia Power Company 2014 Annual Report

	2014	2013	2012
		(in millions)	
Net Income	**$ 1,242**	$ 1,191	$ 1,185
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(3), $-, and $-, respectively	**(5)**	—	—
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $1, respectively	**2**	2	2
Total other comprehensive income (loss)	**(3)**	2	2
Comprehensive Income	**$ 1,239**	$ 1,193	$ 1,187

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2014, 2013, and 2012
Georgia Power Company 2014 Annual Report

	2014	2013	2012
		(in millions)	
Operating Activities:			
Net income	$ 1,242	$ 1,191	$ 1,185
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	1,019	979	912
Deferred income taxes	352	476	377
Allowance for equity funds used during construction	(45)	(30)	(53)
Retail fuel cost over recovery — long-term	(44)	(123)	123
Pension, postretirement, and other employee benefits	19	66	21
Pension and postretirement funding	(156)	(8)	(12)
Other, net	39	38	(12)
Changes in certain current assets and liabilities —			
-Receivables	(248)	(58)	205
-Fossil fuel stock	303	250	(269)
-Prepaid income taxes	(216)	(17)	(7)
-Other current assets	(37)	40	(53)
-Accounts payable	16	67	(165)
-Accrued taxes	17	(14)	(76)
-Accrued compensation	62	(37)	(18)
-Retail fuel cost over-recovery — short-term	(14)	(49)	107
-Other current liabilities	54	(5)	30
Net cash provided from operating activities	2,363	2,766	2,295
Investing Activities:			
Property additions	(2,023)	(1,743)	(1,723)
Investment in restricted cash from pollution control bonds	—	(89)	(284)
Distribution of restricted cash from pollution control bonds	—	89	284
Nuclear decommissioning trust fund purchases	(671)	(706)	(852)
Nuclear decommissioning trust fund sales	669	705	850
Cost of removal, net of salvage	(65)	(59)	(82)
Change in construction payables, net of joint owner portion	(54)	(67)	(149)
Prepaid long-term service agreements	(70)	(18)	(34)
Other investing activities	8	(2)	17
Net cash used for investing activities	(2,206)	(1,890)	(1,973)
Financing Activities:			
Increase (decrease) in notes payable, net	(891)	1,047	(513)
Proceeds —			
Capital contributions from parent company	549	37	42
Pollution control revenue bonds issuances and remarketings	40	194	284
Senior notes issuances	—	850	2,300
FFB loan	1,200	—	—
Redemptions and repurchases —			
Pollution control revenue bonds	(37)	(298)	(284)
Senior notes	—	(1,775)	(850)
Other long-term debt	—	—	(250)
Payment of preferred and preference stock dividends	(17)	(17)	(17)
Payment of common stock dividends	(954)	(907)	(983)
FFB loan issuance costs	(49)	(5)	(3)
Other financing activities	(4)	(17)	(16)
Net cash used for financing activities	(163)	(891)	(290)
Net Change in Cash and Cash Equivalents	(6)	(15)	32
Cash and Cash Equivalents at Beginning of Year	30	45	13
Cash and Cash Equivalents at End of Year	$ 24	$ 30	$ 45
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $18, $14 and $21 capitalized, respectively)	$ 319	$ 344	$ 337
Income taxes (net of refunds)	507	298	312
Noncash transactions — accrued property additions at year-end	154	208	261

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

BALANCE SHEETS
At December 31, 2014 and 2013
Georgia Power Company 2014 Annual Report

Assets	2014	2013
		(in millions)
Current Assets:		
Cash and cash equivalents	$ 24	$ 30
Receivables —		
Customer accounts receivable	553	512
Unbilled revenues	201	209
Joint owner accounts receivable	121	67
Other accounts and notes receivable	61	117
Affiliated companies	18	21
Accumulated provision for uncollectible accounts	(6)	(5)
Fossil fuel stock, at average cost	439	742
Materials and supplies, at average cost	438	409
Vacation pay	91	88
Prepaid income taxes	278	97
Other regulatory assets, current	136	106
Other current assets	74	53
Total current assets	2,428	2,446
Property, Plant, and Equipment:		
In service	31,083	30,132
Less accumulated provision for depreciation	11,222	10,970
Plant in service, net of depreciation	19,861	19,162
Other utility plant, net	211	240
Nuclear fuel, at amortized cost	563	523
Construction work in progress	4,031	3,500
Total property, plant, and equipment	24,666	23,425
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	58	46
Nuclear decommissioning trusts, at fair value	789	751
Miscellaneous property and investments	38	44
Total other property and investments	885	841
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	698	718
Prepaid pension costs	—	118
Deferred under recovered regulatory clause revenues	197	—
Other regulatory assets, deferred	1,753	1,113
Other deferred charges and assets	403	246
Total deferred charges and other assets	3,051	2,195
Total Assets	$ 31,030	$ 28,907

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

BALANCE SHEETS
At December 31, 2014 and 2013
Georgia Power Company 2014 Annual Report

Liabilities and Stockholder's Equity	2014	2013
		(in millions)
Current Liabilities:		
Securities due within one year	$ 1,154	$ 5
Notes payable	156	1,047
Accounts payable —		
Affiliated	451	417
Other	555	472
Customer deposits	253	246
Other accrued taxes	332	321
Accrued interest	96	91
Accrued vacation pay	63	61
Accrued compensation	153	80
Liabilities from risk management activities	32	13
Other regulatory liabilities, current	21	17
Over recovered regulatory clause revenues, current	—	14
Other current liabilities	204	122
Total current liabilities	3,470	2,906
Long-Term Debt (See accompanying statements)	8,683	8,633
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	5,507	5,200
Deferred credits related to income taxes	106	112
Accumulated deferred investment tax credits	196	203
Employee benefit obligations	903	542
Asset retirement obligations	1,223	1,210
Other cost of removal obligations	46	43
Other deferred credits and liabilities	209	201
Total deferred credits and other liabilities	8,190	7,511
Total Liabilities	20,343	19,050
Preferred Stock (See accompanying statements)	45	45
Preference Stock (See accompanying statements)	221	221
Common Stockholder's Equity (See accompanying statements)	10,421	9,591
Total Liabilities and Stockholder's Equity	$ 31,030	$ 28,907
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2014 and 2013
Georgia Power Company 2014 Annual Report

	2014	2013	2014	2013
		(in millions)		*(percent of total)*
Long-Term Debt:				
Long-term notes payable —				
Variable rates (0.56% to 0.63% at 1/1/15) due 2016	**450**	450		
0.625% to 5.25% due 2015	**1,050**	1,050		
3.00% due 2016	**250**	250		
5.70% due 2017	**450**	450		
5.40% due 2018	**250**	250		
4.25% due 2019	**500**	500		
2.85% to 5.95% due 2022-2043	**3,975**	3,975		
Total long-term notes payable	**6,925**	6,925		
Other long-term debt —				
Pollution control revenue bonds:				
0.80% to 4.00% due 2022-2049	**818**	818		
Variable rates (0.03% to 0.04% at 1/1/15) due 2015	**98**	—		
Variable rate (0.04% at 1/1/15) due 2016	**4**	4		
Variable rate (0.04% at 1/1/14) due 2018	**—**	20		
Variable rates (0.01% to 0.09% at 1/1/15) due 2022-2052	**763**	838		
FFB loans (3.00% to 3.86%) due 2044	**1,200**	—		
Total other long-term debt	**2,883**	1,680		
Capitalized lease obligations	**40**	45		
Unamortized debt discount	**(11)**	(12)		
Total long-term debt (annual interest requirement — $342 million)	**9,837**	8,638		
Less amount due within one year	**1,154**	5		
Long-term debt excluding amount due within one year	**8,683**	8,633	**44.8%**	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 — $17 million)	**266**	266	**1.4**	1.4
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 20,000,000 shares				
Outstanding — 9,261,500 shares	**398**	398		
Paid-in capital	**6,196**	5,633		
Retained earnings	**3,835**	3,565		
Accumulated other comprehensive loss	**(8)**	(5)		
Total common stockholder's equity	**10,421**	9,591	**53.8**	51.9
Total Capitalization	**$ 19,370**	$ 18,490	**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, 2014, 2013, and 2012
Georgia Power Company 2014 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, 2011	9	$ 398	$ 5,522	$ 3,112	$ (9)	$ 9,023
Net income after dividends on preferred and preference stock	—	—	—	1,168	—	1,168
Capital contributions from parent company	—	—	63	—	—	63
Other comprehensive income (loss)	—	—	—	—	2	2
Cash dividends on common stock	—	—	—	(983)	—	(983)
Balance at December 31, 2012	9	398	5,585	3,297	(7)	9,273
Net income after dividends on preferred and preference stock	—	—	—	1,174	—	1,174
Capital contributions from parent company	—	—	48	—	—	48
Other comprehensive income (loss)	—	—	—	—	2	2
Cash dividends on common stock	—	—	—	(907)	—	(907)
Other	—	—	—	1	—	1
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**

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

[This page intentionally left blank]

Index to the Notes to Financial Statements

Note		Page
1	Summary of Significant Accounting Polices	II-236
2	Retirement Benefits	II-243
3	Contingencies and Regulatory Matters	II-253
4	Joint Ownership Agreements	II-259
5	Income Taxes	II-260
6	Financing	II-263
7	Commitments	II-266
8	Stock Compensation	II-268
9	Nuclear Insurance	II-269
10	Fair Value Measurements	II-270
11	Derivatives	II-273
12	Quarterly Financial Information (Unaudited)	II-278

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (the Company) is a wholly-owned subsidiary of The Southern Company (Southern Company), which is the parent company of the Company and three other traditional operating companies, as well as Southern Power, SCS, SouthernLINC Wireless, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, and other direct and indirect subsidiaries. The traditional operating companies – the Company, Alabama Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area 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. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public, and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants, including the Company's Plant Hatch and Plant Vogtle.

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. The Company follows GAAP in the U.S. and complies 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

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

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 $555 million in 2014, $504 million in 2013, and $540 million in 2012. 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 $643 million in 2014, $555 million in 2013, and $574 million in 2012.

The Company has entered into several PPAs with Southern Power for capacity and energy. Expenses associated with these PPAs were $144 million, $136 million, and $147 million in 2014, 2013, and 2012, respectively. Additionally, the Company had $15 million of prepaid capacity expenses included in deferred charges and other assets in the balance sheets at December 31, 2014 and 2013. 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 $9 million in 2014, $10 million in 2013, and $7 million in 2012. See Note 4 for additional information.

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 2014, 2013, or 2012.

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

Regulatory Assets and Liabilities

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

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

	2014	2013	Note
	(in millions)		
Retiree benefit plans	$ 1,325	$ 691	(a, j)
Deferred income tax charges	668	684	(b, j)
Deferred income tax charges — Medicare subsidy	34	38	(c)
Loss on reacquired debt	163	181	(d, j)
Asset retirement obligations	108	137	(b, j)
Fuel-hedging (realized and unrealized) losses	29	22	(e, j)
Vacation pay	91	88	(f, j)
Building lease	31	37	(g, j)
Cancelled construction projects	67	70	(h)
Remaining net book value of retired units	25	28	(i)
Storm damage reserves	98	37	(c)
Other regulatory assets	63	49	(c)
Other cost of removal obligations	(60)	(58)	(b)
Deferred income tax credits	(106)	(112)	(b, j)
Other regulatory liabilities	(7)	(6)	(e, j)
Total regulatory assets (liabilities), net	$ 2,529	$ 1,886	

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. At December 31, 2014, other cost of removal obligations included $29 million that will be amortized over the remaining two-year period of January 2015 through December 2016 in accordance with the Company's 2013 ARP.

(c) Recorded and recovered or amortized as approved by the Georgia PSC over periods generally not exceeding eight years.

(d) 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 38 years.

(e) Fuel-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 through the Company's fuel cost recovery mechanism.

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

(g) See Note 6 under "Capital Leases." Recovered over the remaining life of the building through 2020.

(h) 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.

(i) Amortized as approved by the Georgia PSC over periods not exceeding 10 years or through 2022.

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

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any

impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

Revenues

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

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel. See Note 3 under "Retail Regulatory Matters – Nuclear Waste Fund Fee" for additional information.

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. State ITCs are recognized in the period in which the credits are claimed on the state income tax return. A portion of the ITCs available to reduce income taxes payable was not utilized currently and will be carried forward and utilized in future years.

In accordance with accounting standards related to the uncertainty in income taxes, 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:

	2014	2013
	(in millions)	
Generation	$ 15,201	$ 14,872
Transmission	5,086	4,859
Distribution	8,913	8,620
General	1,855	1,753
Plant acquisition adjustment	28	28
Total plant in service	$ 31,083	$ 30,132

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 2.7% in 2014, 3.0% in 2013, and 2.9% in 2012. 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.

In 2009, the Georgia PSC approved an accounting order allowing the Company to amortize a portion of its regulatory liability related to other cost of removal obligations. Under the terms of the Company's Alternate Rate Plan for the years 2011 through 2013 (2010 ARP), the Company amortized approximately $31 million annually of the remaining regulatory liability related to other cost of removal obligations over the three years ended December 31, 2013. Under the terms of the 2013 ARP, an additional $14 million is being amortized annually over the three years ending December 31, 2016.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) are computed as the present value of the 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. The Company has received accounting guidance from the Georgia 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 ARO liability 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, as well as various landfill sites, ash ponds, 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:

	2014	2013
	(in millions)	
Balance at beginning of year	$ 1,222	$ 1,105
Liabilities incurred	9	2
Liabilities settled	(12)	(13)
Accretion	53	55
Cash flow revisions	(17)	73
Balance at end of year	$ 1,255	$ 1,222

The 2014 decrease in cash flow revisions is primarily related to settled AROs for asbestos remediation. The 2013 increase in cash flow revisions is related to updated estimates for ash ponds in connection with the retirement of certain coal-fired generating units and revisions to the nuclear decommissioning AROs based on the latest decommissioning study.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in landfills and surface impoundments at active generating power plants. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $390 million and ongoing post-closure care of approximately $62 million. The Company has previously recorded AROs associated with ash ponds of $500 million, or $458 million on a nominal dollar basis, based on existing state requirements. During 2015, the Company will record AROs for any incremental estimated

closure costs resulting from acceleration in the timing of any currently planned closures and for differences between existing state requirements and the requirements of the CCR Rule. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Nuclear Decommissioning

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

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

The Funds participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to institutional investors for a fee. Securities loaned are fully collateralized by cash, letters of credit, and/or securities issued or guaranteed by the U.S. government or its agencies or instrumentalities. As of December 31, 2014 and 2013, approximately $51 million and $32 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 $52 million and $33 million at December 31, 2014 and 2013, 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, 2014, investment securities in the Funds totaled $789 million, consisting of equity securities of $303 million, debt securities of $475 million, and $11 million of other securities. At December 31, 2013, investment securities in the Funds totaled $751 million, consisting of equity securities of $330 million, debt securities of $397 million, and $24 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 $669 million, $705 million, and $850 million in 2014, 2013, and 2012, respectively, all of which were reinvested. For 2014, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $44 million, of which an immaterial amount related to unrealized gains and losses on securities held in the Funds at December 31, 2014. For 2013, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $61 million, of which $34 million related to unrealized gains on securities held in the Funds at December 31, 2013. For 2012, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $67 million, of which $25 million related to unrealized losses on securities held in the Funds at December 31, 2012. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of the securities and purpose for which the securities were acquired.

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

Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning are based on the most current study performed in 2012. The site study costs and external trust funds for decommissioning as of December 31, 2014 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	2068	2072
	(in millions)	
Site study costs:		
Radiated structures	$ 549	$ 453
Spent fuel management	131	115
Non-radiated structures	51	76
Total site study costs	$ 731	$ 644
External trust funds	$ 496	$ 293

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 through 2016 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 periodically review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs.

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. For the years 2014, 2013, and 2012, the average AFUDC rates were 5.6%, 5.3%, and 6.8%, respectively, and AFUDC capitalized was $62 million, $44 million, and $75 million, respectively. AFUDC, net of income taxes, was 4.6%, 3.3%, and 5.7% of net income after dividends on preferred and preference stock for 2014, 2013, and 2012, 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, 2014 and December 31, 2013, the balance in the regulatory asset related to storm damage was $98 million and $37 million, respectively, with approximately $30 million included in other regulatory assets, current for both years and approximately $68 million and $7 million included in other regulatory assets, deferred, respectively. The Company expects

the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs. As a result of the regulatory treatment, costs related to storms are generally not expected to have a material impact on the Company's financial statements.

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 from 2014 through 2016. The Company recovered approximately $3 million annually through the ECCR tariff from 2011 through 2013 under the 2010 ARP. 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 financial statements. As of December 31, 2014, the balance of the environmental remediation liability was $22 million, with approximately $2 million included in other regulatory assets, current and approximately $14 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 charged 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 (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 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. See Note 11 for additional information regarding derivatives.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2014.

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). In December 2014, the Company voluntarily contributed $150 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. 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, 2015, other postretirement trust contributions are expected to total approximately $17 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2011 for the 2012 plan year using discount rates for the pension plans and the other postretirement benefit plans of 4.98% and 4.87%, respectively, and an annual salary increase of 3.84%.

	2014	2013	2012
Discount rate:			
Pension plans	**4.18%**	5.02%	4.27%
Other postretirement benefit plans	**4.03**	4.85	4.04
Annual salary increase	**3.59**	3.59	3.59
Long-term return on plan assets:			
Pension plans	**8.20**	8.20	8.20
Other postretirement benefit plans	**6.75**	6.74	7.24

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

For purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $226 million and $46 million, respectively.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2014 were as follows:

	Initial Cost Trend Rate	**Ultimate Cost Trend Rate**	**Year That Ultimate Rate is Reached**
Pre-65	9.00%	4.50%	2024
Post-65 medical	6.00	4.50	2024
Post-65 prescription	6.75	4.50	2024

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, 2014 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 69	$ (58)
Service and interest costs	3	(2)

Pension Plans

The total accumulated benefit obligation for the pension plans was $3.5 billion at December 31, 2014 and $2.9 billion at December 31, 2013. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 3,116	$ 3,312
Service cost	62	69
Interest cost	153	138
Benefits paid	(149)	(141)
Actuarial (gain) loss	599	(262)
Balance at end of year	3,781	3,116
Change in plan assets		
Fair value of plan assets at beginning of year	3,085	2,827
Actual return on plan assets	285	387
Employer contributions	162	12
Benefits paid	(149)	(141)
Fair value of plan assets at end of year	3,383	3,085
Accrued liability	$ (398)	$ (31)

At December 31, 2014, the projected benefit obligations for the qualified and non-qualified pension plans were $3.6 billion and $165 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's pension plans consist of the following:

	2014	2013
	(in millions)	
Prepaid pension costs	$ —	$ 118
Other regulatory assets, deferred	1,102	610
Current liabilities, other	(12)	(12)
Employee benefit obligations	(386)	(137)

Presented below are the amounts included in regulatory assets at December 31, 2014 and 2013 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 2015.

	2014	2013	Estimated Amortization in 2015
		(in millions)	
Prior service cost	$ 17	$ 26	$ 9
Net (gain) loss	1,085	584	76
Regulatory assets	$ 1,102	$ 610	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in millions)	
Regulatory assets:		
Beginning balance	$ 610	$ 1,132
Net (gain) loss	543	(438)
Reclassification adjustments:		
Amortization of prior service costs	(10)	(10)
Amortization of net gain (loss)	(41)	(74)
Total reclassification adjustments	(51)	(84)
Total change	492	(522)
Ending balance	$ 1,102	$ 610

Components of net periodic pension cost were as follows:

	2014	2013	2012
		(in millions)	
Service cost	$ 62	$ 69	$ 60
Interest cost	153	138	141
Expected return on plan assets	(228)	(212)	(221)
Recognized net loss	41	74	33
Net amortization	10	10	12
Net periodic pension cost	$ 38	$ 79	$ 25

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, 2014, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2015	$ 199
2016	169
2017	177
2018	183
2019	190
2020 to 2024	1,042

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 723	$ 800
Service cost	6	7
Interest cost	34	31
Benefits paid	(44)	(45)
Actuarial (gain) loss	142	(73)
Retiree drug subsidy	3	3
Balance at end of year	864	723
Change in plan assets		
Fair value of plan assets at beginning of year	407	382
Actual return on plan assets	21	56
Employer contributions	8	11
Benefits paid	(41)	(42)
Fair value of plan assets at end of year	395	407
Accrued liability	$ (469)	$ (316)

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's other postretirement benefit plans consist of the following:

	2014	2013
	(in millions)	
Other regulatory assets, deferred	$ 213	$ 69
Employee benefit obligations	(469)	(316)

Presented below are the amounts included in regulatory assets at December 31, 2014 and 2013 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 2015.

	2014	2013	Estimated Amortization in 2015
		(in millions)	
Prior service cost	$ (5)	$ (4)	$ —
Net (gain) loss	**218**	73	**11**
Regulatory assets	$ **213**	$ 69	

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
		(in millions)
Regulatory assets:		
Beginning balance	$ **69**	$ 187
Net (gain) loss	**146**	(106)
Reclassification adjustments:		
Amortization of transition obligation	**—**	(4)
Amortization of net gain (loss)	**(2)**	(8)
Total reclassification adjustments	**(2)**	(12)
Total change	**144**	(118)
Ending balance	$ **213**	$ 69

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

	2014	2013	2012
		(in millions)	
Service cost	$ **6**	$ 7	$ 7
Interest cost	**34**	31	37
Expected return on plan assets	**(25)**	(24)	(29)
Net amortization	**2**	12	10
Net periodic postretirement benefit cost	$ **17**	$ 26	$ 25

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)	
2015	$ 53	$ (4)	$ 49
2016	56	(5)	51
2017	57	(5)	52
2018	59	(6)	53
2019	59	(6)	53
2020 to 2024	289	(32)	257

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, 2014 and 2013, along with the targeted mix of assets for each plan, is presented below:

	Target	2014	2013
Pension plan assets:			
Domestic equity	26%	**30%**	31%
International equity	25	**23**	25
Fixed income	23	**27**	23
Special situations	3	**1**	1
Real estate investments	14	**14**	14
Private equity	9	**5**	6
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	40%	**38%**	36%
International equity	21	**26**	30
Domestic fixed income	24	**24**	21
Global fixed income	8	**7**	8
Special situations	1	**—**	—
Real estate investments	4	**4**	3
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, 2014 and 2013. 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 and private equity.*** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

The fair values of pension plan assets as of December 31, 2014 and 2013 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 595	$ 246	$ —	$ 841
International equity*	373	344	—	717
Fixed income:				
U.S. Treasury, government, and agency bonds	—	244	—	244
Mortgage- and asset-backed securities	—	66	—	66
Corporate bonds	—	398	—	398
Pooled funds	—	179	—	179
Cash equivalents and other	1	230	—	231
Real estate investments	102	—	391	493
Private equity	—	—	199	199
Total	$ 1,071	$ 1,707	$ 590	$ 3,368
Liabilities:				
Derivatives	$ (1)	$ —	$ —	$ (1)
Total	$ 1,070	$ 1,707	$ 590	$ 3,367

* 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, 2013:	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)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 506	$ 296	$ —	$ 802
International equity*	389	359	—	748
Fixed income:				
U.S. Treasury, government, and agency bonds	—	212	—	212
Mortgage- and asset-backed securities	—	55	—	55
Corporate bonds	—	346	—	346
Pooled funds	—	166	—	166
Cash equivalents and other	—	79	—	79
Real estate investments	92	—	353	445
Private equity	—	—	202	202
Total	$ 987	$ 1,513	$ 555	$ 3,055
Liabilities:				
Derivatives	$ —	$ (1)	$ —	$ (1)
Total	$ 987	$ 1,512	$ 555	$ 3,054

* 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.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2014 and 2013 were as follows:

	2014		2013	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in millions)		
Beginning balance	$ 353	$ 202	$ 299	$ 211
Actual return on investments:				
Related to investments held at year end	23	15	25	3
Related to investments sold during the year	12	(6)	10	17
Total return on investments	35	9	35	20
Purchases, sales, and settlements	3	(12)	19	(29)
Ending balance	$ 391	$ 199	$ 353	$ 202

The fair values of other postretirement benefit plan assets as of December 31, 2014 and 2013 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 53	$ 40	$ —	$ 93
International equity*	11	45	—	56
Fixed income:				
U.S. Treasury, government, and agency bonds	—	7	—	7
Mortgage- and asset-backed securities	—	2	—	2
Corporate bonds	—	12	—	12
Pooled funds	—	29	—	29
Cash equivalents and other	8	11	—	19
Trust-owned life insurance	—	162	—	162
Real estate investments	3	—	12	15
Private equity	—	—	6	6
Total	$ 75	$ 308	$ 18	$ 401

* 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, 2013:	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)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 74	$ 25	$ —	$ 99
International equity*	12	57	—	69
Fixed income:				
U.S. Treasury, government, and agency bonds	—	7	—	7
Mortgage- and asset-backed securities	—	2	—	2
Corporate bonds	—	11	—	11
Pooled funds	—	34	—	34
Cash equivalents and other	—	6	—	6
Trust-owned life insurance	—	158	—	158
Real estate investments	3	—	11	14
Private equity	—	—	6	6
Total	$ 89	$ 300	$ 17	$ 406

* 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.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2014 and 2013 were as follows:

	2014		2013	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in millions)		
Beginning balance	$ 11	$ 6	$ 10	$ 7
Actual return on investments:				
Related to investments held at year end	1	—	1	—
Related to investments sold during the year	—	—	—	—
Total return on investments	1	—	1	—
Purchases, sales, and settlements	—	—	—	(1)
Ending balance	$ 12	$ 6	$ 11	$ 6

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 2014, 2013, and 2012 were $25 million, $24 million, and $24 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

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against the Company alleging violations of the New Source Review provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by Gulf Power. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. The case against the Company (including claims related to a unit co-owned by Gulf Power) has been administratively closed in the U.S. District Court for the Northern District of Georgia since 2001.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

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 properties. See Note 1 under "Environmental Remediation Recovery" for additional information.

The Company has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a site in Brunswick, Georgia on the CERCLA National Priorities List. The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional cleanup and claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites are anticipated.

The Company and numerous other entities have been designated by the EPA as PRPs at the Ward Transformer Superfund site located in Raleigh, North Carolina. In 2011, the EPA issued a Unilateral Administrative Order (UAO) to the Company and 22 other parties, ordering specific remedial action of certain areas at the site. Later in 2011, the Company filed a response with the EPA stating it has sufficient cause to believe it is not a liable party under CERCLA. The EPA notified the Company in 2011 that it is considering enforcement options against the Company and other non-complying UAO recipients. If the EPA pursues enforcement actions and the court determines that a respondent failed to comply with the UAO without sufficient cause, the EPA may also seek civil penalties of up to $37,500 per day for the violation and punitive damages of up to three times the costs incurred by the EPA as a result of the party's failure to comply with the UAO.

In addition to the EPA's action at this site, the Company, along with many other parties, was sued in a private action by several existing PRPs for cost recovery related to the removal action. In February 2013, the U.S. District Court for the Eastern District of North Carolina Western Division granted the Company's summary judgment motion, ruling that the Company has no liability in the private action. In May 2013, the plaintiffs appealed the U.S. District Court for the Eastern District of North Carolina Western Division's order to the U.S. Court of Appeals for the Fourth Circuit.

The ultimate outcome of these matters will depend upon the success of defenses asserted, the ultimate number of PRPs participating in the cleanup, and numerous other factors and 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.

As a result of its first lawsuit, the Company recovered approximately $27 million, based on its ownership interests, representing the vast majority of the Company's direct costs of the expansion of spent nuclear fuel storage facilities at Plant Hatch and Plant Vogtle Units 1 and 2 from 1998 through 2004. The proceeds were received in 2012 and credited to the Company accounts where the original costs were charged and were used to reduce rate base, fuel, and cost of service for the benefit of customers.

On December 12, 2014, the Court of Federal Claims entered a judgment in favor of the Company in its second spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. The Company was awarded approximately $18 million, based on its ownership interests. No amounts have been recognized in the financial statements as of December 31, 2014. The final outcome of this matter cannot be determined at this time; however, no material impact on the Company's net income is expected.

On March 4, 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. 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, 2014 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 as a significant portion of any damage amounts collected from the government is expected to be credited to the Company accounts where the original costs were charged and used to reduce rate base, fuel, and cost of service for the benefit of customers.

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

Retail Regulatory Matters

Rate Plans

In December 2013, the Georgia PSC voted to approve the 2013 ARP. The 2013 ARP reflects the settlement agreement among the Company, the Georgia PSC's Public Interest Advocacy Staff, and 11 of the 13 intervenors, which was filed with the Georgia PSC in November 2013.

On January 1, 2014, in accordance with the 2013 ARP, the Company increased its tariffs as follows: (1) traditional base tariff rates by approximately $80 million; (2) ECCR tariff by approximately $25 million; (3) Demand-Side Management (DSM) tariffs by approximately $1 million; and (4) Municipal Franchise Fee (MFF) tariff by approximately $4 million, for a total increase in base revenues of approximately $110 million.

On February 19, 2015, in accordance with the 2013 ARP, the Georgia PSC approved adjustments to traditional base, ECCR, DSM, and MFF tariffs effective January 1, 2015 as follows:

- Traditional base tariffs by approximately $107 million to cover additional capacity costs;
- ECCR tariff by approximately $23 million;
- DSM tariffs by approximately $3 million; and
- MFF tariff by approximately $3 million to reflect the adjustments above.

The sum of these adjustments resulted in a base revenue increase of approximately $136 million in 2015.

The 2016 base rate increase, which was approved in the 2013 ARP, will be determined through a compliance filing expected to be filed in late 2015, and will be subject to review by the Georgia PSC.

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. However, if at any time during the term of the 2013 ARP, the Company projects that its retail earnings will be below 10.00% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff that would be used to adjust the Company's earnings back to a 10.00% retail ROE. The Georgia PSC would have 90 days to rule on the Company's request. The ICR tariff will expire at the earlier of January 1, 2017 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, the Company may file a full rate case. In 2014, the Company's retail ROE exceeded 12.00%, and the Company expects to refund to retail customers approximately $13 million in 2015, subject to review and approval by the Georgia PSC.

Except as provided above, the Company will not file for a general base rate increase while the 2013 ARP is in effect. The Company is required to file a general rate case by July 1, 2016, in response to which the Georgia PSC would be expected to determine whether the 2013 ARP should be continued, modified, or discontinued.

Integrated Resource Plans

In July 2013, the Georgia PSC approved the Company's latest triennial Integrated Resource Plan (2013 IRP) including the Company's request to decertify 16 coal- and oil-fired units totaling 2,093 MWs. Several factors, including the cost to comply with existing and future environmental regulations, recent and forecasted economic conditions, and lower natural gas prices, contributed to the decision to close these units.

Plant Branch Units 3 and 4 (1,016 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) will be decertified and retired by April 16, 2015, the compliance date of the Mercury and Air Toxics Standards (MATS) rule. The decertification date of Plant Branch Unit 1 (250 MWs) was extended from December 31, 2013 as specified in the final order in the 2011 Integrated Resource Plan Update (2011 IRP Update) to coincide with the decertification date of Plant Branch Units 3 and 4. The decertification and retirement of Plant Kraft Units 1 through 4 (316 MWs) were also approved and will be effective by April 16, 2016, based on a one-year extension of the MATS rule compliance date that was approved by the State of Georgia Environmental Protection Division in September 2013 to allow for necessary transmission system reliability improvements. In July 2013, the Georgia PSC approved the switch to natural gas as the primary fuel for Plant Yates Units 6 and 7. In September 2013, Plant Branch Unit 2 (319 MWs) was retired as approved by the Georgia PSC in the 2011 IRP Update in order to comply with the State of Georgia's Multi-Pollutant Rule.

In the 2013 ARP, the Georgia PSC approved the amortization of the CWIP balances related to environmental projects that will not be completed at Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 over nine years beginning in January 2014 and the amortization of any remaining net book values of Plant Branch Unit 2 from October 2013 to December 2022, Plant Branch Unit 1 from May 2015 to December 2020, Plant Branch Unit 3 from May 2015 to December 2023, and Plant Branch Unit 4 from May 2015 to December 2024. The Georgia PSC deferred a decision regarding the appropriate recovery period for the costs associated with unusable materials and supplies remaining at the retiring plants to the Company's next base rate case, which the Company expects to file in 2016 (2016 Rate Case). In the 2013 IRP, the Georgia PSC also deferred decisions regarding the recovery of any fuel related costs that could be incurred in connection with the retirement units to be addressed in future fuel cases.

On July 1, 2014, the Georgia PSC approved the Company's request to cancel the proposed biomass fuel conversion of Plant Mitchell Unit 3 (155 MWs) because it would not be cost effective for customers. The Company expects to request decertification of Plant Mitchell Unit 3 in connection with the triennial Integrated Resource Plan to be filed in 2016. The Company plans to continue to operate the unit as needed until the MATS rule becomes effective in April 2015.

The decertification of these units and fuel conversions are not expected to have a material impact on the Company's financial statements; however, the ultimate outcome depends on the Georgia PSC's order in the 2016 Rate Case and future fuel cases and cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved a reduction in the Company's total annual billings of approximately $567 million effective June 1, 2012, with an additional $122 million reduction effective January 1, 2013 through June 1, 2014. 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 or over recovered fuel balance exceeds $200 million. The Company's fuel cost recovery includes costs associated with a natural gas hedging program as revised and approved by the Georgia PSC in February 2013, requiring it to use options and hedges within a 24-month time horizon. See Note 11 under "Energy-Related Derivatives" for additional information. On January 20, 2015, the Georgia PSC approved the deferral of the Company's next fuel case filing until at least June 30, 2015.

The Company's under recovered fuel balance totaled approximately $199 million at December 31, 2014 and is included in current assets and other deferred charges and assets. At December 31, 2013, the Company's over recovered fuel balance totaled approximately $58 million and was included in current liabilities and 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.

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 (collectively, Vogtle Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc., a subsidiary of The Shaw Group Inc., which was acquired by Chicago Bridge & Iron Company N.V. (CB&I) (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 that is 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. The Contractor's liability to the Vogtle Owners for schedule and performance liquidated damages and warranty claims is subject to a cap. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which have not 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%.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and CB&I's The Shaw Group Inc., respectively. 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. The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay certain termination costs. 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 2009, the NRC issued an Early Site Permit and Limited Work Authorization which allowed limited work to begin on Plant Vogtle Units 3 and 4. The NRC certified the Westinghouse Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, in late 2011, and issued combined construction and operating licenses (COLs) in early 2012. Receipt of the COLs allowed full construction to begin. 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 are expected as construction proceeds.

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 increases to the NCCR tariff of approximately $223 million, $35 million, $50 million, and $60 million, effective January 1, 2011, 2012, 2013, and 2014, respectively. On December 16, 2014, the Georgia PSC approved an increase to the NCCR tariff of approximately $27 million effective January 1, 2015.

In 2012, the Vogtle Owners and the Contractor began negotiations regarding the costs associated with design changes to the DCD and the delays in the timing of approval of the DCD and issuance of the COLs, including the assertion by the Contractor that the Vogtle Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. Also in 2012, the Company and the other Vogtle Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Vogtle Owners are not responsible for these costs. In 2012, the Contractor also filed suit against the Company and the other Vogtle Owners in the U.S. District Court for the District of Columbia alleging the Vogtle Owners are responsible for these costs. In August 2013, the U.S. District Court for the District of Columbia dismissed the Contractor's suit, ruling that the proper venue is the U.S. District Court for the Southern District of Georgia. The Contractor appealed the decision to the U.S. Court of Appeals for the District of Columbia Circuit in September 2013. The portion of additional costs claimed by the Contractor in its initial complaint that would be attributable to the Company (based on the Company's ownership interest) is approximately $425 million (in 2008 dollars). The Contractor also asserted it is entitled to extensions of the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. On May 22, 2014, the Contractor filed an amended counterclaim to the suit pending in the U.S. District Court for the Southern District of Georgia alleging that (i) the design changes to the DCD imposed by the NRC delayed module production and the impacts to the Contractor are recoverable by the Contractor under the Vogtle 3 and 4 Agreement and (ii) the changes to the basemat rebar design

required by the NRC caused additional costs and delays recoverable by the Contractor under the Vogtle 3 and 4 Agreement. The Contractor did not specify in its amended counterclaim the amounts relating to these new allegations; however, the Contractor has subsequently asserted related minimum damages (based on the Company's ownership interest) of $113 million. The Contractor may from time to time continue to assert that it is entitled to additional payments with respect to these allegations, any of which could be substantial. The Company has not agreed to the proposed cost or to any changes to the guaranteed substantial completion dates or that the Vogtle Owners have any responsibility for costs related to these issues. Litigation is ongoing and the Company intends to vigorously defend the positions of the Vogtle Owners. The Company also expects negotiations with the Contractor to continue with respect to cost and schedule during which negotiations the parties may reach a mutually acceptable compromise of their positions.

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. If the projected certified construction capital costs to be borne by the Company increase by 5% or the projected in-service dates are significantly extended, the Company is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. The Company's eighth VCM report filed in February 2013 requested an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 from $4.4 billion to $4.8 billion and to extend the estimated in-service dates to the fourth quarter 2017 and the fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively.

In September 2013, the Georgia PSC approved a stipulation (2013 Stipulation) entered into by 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 accordance with the Georgia Integrated Resource Planning Act, any costs incurred by the Company in excess of the certified amount will be included in rate base, provided the Company shows the costs to be reasonable and prudent. In addition, financing costs on any construction-related costs in excess of the certified amount likely would be subject to recovery through AFUDC instead of the NCCR tariff.

The Georgia PSC has approved eleven VCM reports covering the periods through June 30, 2014, including construction capital costs incurred, which through that date totaled $2.8 billion.

On January 29, 2015, the Company announced that it was notified by the Contractor of the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4, which would incrementally delay the previously disclosed estimated in-service dates by 18 months (from the fourth quarter of 2017 to the second quarter of 2019 for Unit 3 and from the fourth quarter of 2018 to the second quarter of 2020 for Unit 4). The Company has not agreed to any changes to the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. The Company does not believe that the Contractor's revised forecast reflects all efforts that may be possible to mitigate the Contractor's delay.

In addition, the Company believes that, pursuant to the Vogtle 3 and 4 Agreement, the Contractor is responsible for the Contractor's costs related to the Contractor's delay (including any related construction and mitigation costs, which could be material) and that the Vogtle Owners are entitled to recover liquidated damages for the Contractor's delay beyond the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. Consistent with the Contractor's position in the pending litigation described above, the Company expects the Contractor to contest any claims for liquidated damages and to assert that the Vogtle Owners are responsible for additional costs related to the Contractor's delay.

On February 27, 2015, the Company filed its twelfth VCM report with the Georgia PSC covering the period from July 1 through December 31, 2014, which requests approval for an additional $0.2 billion of construction capital costs incurred during that period and reflects the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4 as well as additional estimated owner-related costs of approximately $10 million per month expected to result from the Contractor's proposed 18-month delay, including property taxes, oversight costs, compliance costs, and other operational readiness costs. No Contractor costs related to the Contractor's proposed 18-month delay are included in the twelfth VCM report. Additionally, while the Company has not agreed to any change to the guaranteed substantial completion dates, the twelfth VCM report includes a requested amendment to the Plant Vogtle Units 3 and 4 certificate to reflect the Contractor's revised forecast, to include the estimated owner's costs associated with the proposed 18-month Contractor delay, and to increase the estimated total in-service capital cost of Plant Vogtle Units 3 and 4 to $5.0 billion.

The Company will continue to incur financing costs of approximately $30 million per month until Plant Vogtle Units 3 and 4 are placed in service. The twelfth VCM report estimates total associated financing costs during the construction period to be approximately $2.5 billion.

Processes are in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, 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 issues are expected to 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.

As construction continues, the risk remains that ongoing challenges with Contractor performance including additional challenges in its fabrication, assembly, delivery, and installation of the shield building and structural modules, delays in the receipt of the remaining permits necessary for the operation of Plant Vogtle Units 3 and 4, or other issues could arise and may further impact project schedule and cost. In addition, the IRS allocated production tax credits to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021.

Additional claims by the Contractor or the Company (on behalf of the Vogtle Owners) are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement, but also may be resolved through litigation.

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

Nuclear Waste Fund Fee

In November 2013, the U.S. District Court for the District of Columbia ordered the DOE to cease collecting spent fuel depositary fees from nuclear power plant operators until such time as the DOE either complies with the Nuclear Waste Policy Act of 1982 or until the U.S. Congress enacts an alternative waste management plan. On March 18, 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied the DOE's request for rehearing of the November 2013 panel decision ordering that the DOE propose the nuclear waste fund fee be changed to zero. The DOE formally set the fee to zero effective May 16, 2014. On June 17, 2014, the Georgia PSC approved the Company's request to credit customers the portion of fuel cost related to the nuclear waste fund fee. The nuclear waste fund rider to the Company's fuel tariffs became effective July 1, 2014.

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 $84 million in 2014, $91 million in 2013, and $107 million in 2012 and is included in purchased power, affiliates in the statements of income. The Company accounts for SEGCO using the equity method.

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 who is the operator of the plant. The Company and Duke Energy Florida, Inc. jointly own a combustion turbine unit (Intercession City) operated by Duke Energy Florida, Inc.

At December 31, 2014, 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%	$ 3,420	$ 2,059	$ 46
Plant Hatch (nuclear)	50.1	1,117	559	66
Plant Wansley (coal)	53.5	856	278	15
Plant Scherer (coal)				
Units 1 and 2	8.4	254	83	1
Unit 3	75.0	1,172	417	10
Rocky Mountain (pumped storage)	25.4	182	124	2
Intercession City (combustion-turbine)	33.3	14	5	—

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 that are currently under construction. 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 combined state income tax returns for the States of Alabama, Georgia, and Mississippi. 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:

	2014	2013	2012
		(in millions)	
Federal –			
Current	$ 295	$ 277	$ 273
Deferred	366	374	370
	661	651	643
State –			
Current	82	(30)	38
Deferred	(14)	102	7
	68	72	45
Total	$ 729	$ 723	$ 688

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:

	2014	2013
	(in millions)	
Deferred tax liabilities –		
Accelerated depreciation	$ 4,732	$ 4,479
Property basis differences	811	873
Employee benefit obligations	329	232
Under-recovered fuel costs	81	—
Premium on reacquired debt	66	73
Regulatory assets associated with employee benefit obligations	534	276
Asset retirement obligations	497	495
Other	160	168
Total	7,210	6,596
Deferred tax assets –		
Federal effect of state deferred taxes	148	159
Employee benefit obligations	642	388
Other property basis differences	86	93
Other deferred costs	86	84
Cost of removal obligations	11	17
State tax credit carry forward	170	118
Federal tax credit carry forward	5	3
Over-recovered fuel costs	—	22
Unbilled fuel revenue	46	53
Asset retirement obligations	497	495
Other	46	32
Total	1,737	1,464
Total deferred tax liabilities, net	5,473	5,132
Portion included in current assets/(liabilities), net	34	68
Accumulated deferred income taxes	$ 5,507	$ 5,200

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

At December 31, 2014, tax-related regulatory assets to be recovered from customers were $702 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, 2014, tax-related regulatory liabilities to be credited to customers were $106 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 2011, the Company recorded a regulatory liability of $62 million related to a settlement with the Georgia Department of Revenue resolving claims for certain tax credits in 2005 through 2009. Amortization of the regulatory liability occurred ratably over the period from April 2012 through December 2013.

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 $10 million in 2014, $5 million in 2013, and $13 million in 2012. State ITCs are recognized in the period in which the credits are claimed on the state income tax return and totaled $34 million in 2014, $27 million in 2013, and $36 million in 2012. At December 31, 2014, the Company had $5 million in federal tax credit carry forwards that will expire by 2034 and $152 million in state ITC carry forwards that will expire between 2021 and 2025.

Effective Tax Rate

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

	2014	2013	2012
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.2**	2.5	1.6
Non-deductible book depreciation	**1.3**	1.3	1.2
AFUDC equity	**(0.8)**	(0.6)	(1.0)
Other	**(0.7)**	(0.4)	(0.1)
Effective income tax rate	**37.0%**	37.8%	36.7%

The decrease in the Company's 2014 effective tax rate is primarily the result of benefits related to emission allowances and state apportionment. The increase in the Company's 2013 effective tax rate is primarily the result of a decrease in state income tax credits and non-taxable AFUDC equity.

Unrecognized Tax Benefits

The Company had no unrecognized tax benefits during 2014. Changes in unrecognized tax benefits in prior years were as follows:

	2013	2012
	(in millions)	
Unrecognized tax benefits at beginning of year	$ 23	$ 47
Tax positions increase from current periods	—	3
Tax positions increase from prior periods	—	3
Tax positions decrease from prior periods	(23)	(19)
Reductions due to settlements	—	(8)
Reductions due to expired statute of limitations	—	(3)
Balance at end of year	$ —	$ 23

The tax positions decrease from prior periods for 2013 and 2012 relate primarily to the tax accounting method change for repairs-generation assets and did not impact the effective tax rate. See "Tax Method of Accounting for Repairs" herein for additional information.

These amounts are presented on a gross basis without considering the related federal or state income tax impact.

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.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 federal income tax return and has received a partial acceptance letter from the IRS; however, the IRS has not finalized its audit. 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 2008.

Tax Method of Accounting for Repairs

In 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. Additionally, in April 2013, the IRS issued Revenue Procedure 2013-24, which provides guidance for taxpayers related to the deductibility of repair costs associated with generation assets. Based on a review of the regulations, Southern Company incorporated provisions related to repair costs for generation assets into its consolidated 2012 federal income tax return and reversed all related unrecognized tax positions. In September 2013, the IRS issued Treasury Decision 9636, "Guidance Regarding Deduction and Capitalization of Expenditures Related to Tangible Property," which are final tangible property regulations applicable to taxable years beginning on or after January 1, 2014. Southern Company continues to review this guidance; however, these regulations are not expected to have a material impact on the Company's financial statements.

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:

	2014	2013
	(in millions)	
Senior notes	$ 1,050	$ —
Pollution control revenue bonds	98	—
Capital lease	6	5
Total	$ 1,154	$ 5

Maturities through 2019 applicable to total long-term debt are as follows: $1.2 billion in 2015; $710 million in 2016; $457 million in 2017; $257 million in 2018; and $508 million in 2019.

Senior Notes

The Company did not issue any unsecured senior notes in 2014. At December 31, 2014 and 2013, the Company had $6.9 billion of senior notes outstanding. These senior notes are effectively subordinated to all secured debt of the Company, which aggregated $1.2 billion and $45 million at December 31, 2014 and 2013, respectively. As of December 31, 2014, the Company's secured debt included borrowings of $1.2 billion guaranteed by the DOE and capital leases. As of December 31, 2013, the Company's secured debt was related to capital lease obligations. See Note 7 for additional information.

See "DOE Loan Guarantee Borrowings" herein for additional information.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2014 and 2013 was $1.6 billion and $1.7 billion, respectively. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

In July 2014, the Company reoffered to the public $40 million aggregate principal amount of Development Authority of Monroe County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), First Series 2009, which had been previously purchased and held by the Company since 2010.

Bank Term Loans

In February 2014, the Company repaid three four-month floating rate bank loans in an aggregate principal amount of $400 million. At December 31, 2014, the Company had no bank term loans outstanding.

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) on February 20, 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 will 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 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%.

On February 20, 2014, the Company made initial borrowings under the FFB Credit Facility in an aggregate principal amount of $1.0 billion. The interest rate applicable to $500 million of the initial advance under the FFB Credit Facility is 3.860% for an interest period that extends to 2044 and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to 2029, and is expected to be reset from time to time thereafter through 2044. In connection with its entry into the agreements with the DOE and the FFB, the Company incurred issuance costs of approximately $66 million, which will be amortized over the life of the borrowings under the FFB Credit Facility.

On December 11, 2014, the Company made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $200 million. The interest rate applicable to the $200 million advance in December 2014 under the FFB Credit Facility is 3.002% for an interest period that extends to 2044.

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, compliance with the Cargo Preference Act of 1954, 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). 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, 2014 and 2013, the Company had a capital lease asset for its corporate headquarters building of $61 million, with accumulated depreciation at December 31, 2014 and 2013 of $21 million and $16 million, respectively. At December 31, 2014 and 2013, the capitalized lease obligation was $40 million and $45 million, respectively, with an annual interest rate of 7.9% for both years. For ratemaking purposes, the Georgia PSC has allowed only the lease payments in cost of service. The difference between the accrued expense and the lease payments allowed for ratemaking purposes has been deferred and is being amortized to expense as ordered by the Georgia PSC. The annual expense incurred for all capital leases was not material for any year presented. See Note 7 under "Fuel and Purchased Power Agreements" for additional information on capital lease PPAs that become effective in 2015.

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, 2014, committed credit arrangements with banks were as follows:

Expires[a]			
2016	2018	Total	Unused
	(in millions)		
$150	$1,600	$1,750	$1,736

(a) No credit arrangements expire in 2015 or 2017.

Subject to applicable market conditions, the Company expects to renew its bank credit arrangements, as needed, prior to expiration. All 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.

The 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.

A portion of the $1.7 billion unused credit with banks is allocated to provide liquidity support to the Company's variable rate 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, 2014 was $865 million. In addition, at December 31, 2014, the Company had $118 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months. As of December 31, 2014, $98 million of certain pollution control revenue bonds of the Company were reclassified to securities due within one year in anticipation of their redemption in connection with unit retirement decisions. See Note 3 under "Retail Regulatory Matters – Integrated Resource Plans" for additional information.

The Company makes short-term borrowings 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 term loans are included in notes payable in the balance sheets.

The Company had $156 million and $1.0 billion of short-term debt outstanding at December 31, 2014 and 2013, respectively. Details of short-term borrowings outstanding were as follows:

	Short-term Debt at the End of the Period	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2014:		
Commercial paper	$ 156	0.3%
December 31, 2013:		
Commercial paper	$ 647	0.2%
Short-term bank debt	400	0.9%
Total	$ 1,047	0.5%

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 2014, 2013, and 2012, the Company incurred fuel expense of $2.5 billion, $2.3 billion, and $2.1 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 Unit 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 $19 million, $27 million, and $50 million in 2014, 2013, and 2012, 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 $167 million, $162 million, and $169 million for 2014, 2013, and 2012, respectively. Estimated total long-term obligations at December 31, 2014 were as follows:

	Affiliate Capital Leases	Affiliate Operating Leases	Non-Affiliate Operating Leases [4]	Vogtle Units 1 and 2 Capacity Payments	Total ($)
			(in millions)		
2015	$ 22	$ 90	$ 114	$ 11	$ 237
2016	22	100	117	11	250
2017	23	71	146	10	250
2018	23	62	150	7	242
2019	23	63	152	6	244
2020 and thereafter	255	606	1,572	50	2,483
Total	$ 368	$ 992	$ 2,251	$ 95	$ 3,706
Less: amounts representing executory costs[1]	55				
Net minimum lease payments	313				
Less: amounts representing interest[2]	85				
Present value of net minimum lease payments[3]	$ 228				

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

(2) Amount necessary to reduce minimum lease payments to present value calculated at the Company's incremental borrowing rate at the inception of the leases.

(3) Once service commences under the PPAs beginning in 2015, the Company will recognize capital lease assets and capital lease obligations totaling $149 million, being the lesser of the estimated fair value of the lease property or the present value of the net minimum lease payments.

(4) A total of $1.1 billion of biomass PPAs included under the non-affiliate operating leases is contingent upon the counterparties meeting specified contract dates for commercial operation and may change 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 operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

In addition to the 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 2014, $32 million for 2013, and $34 million for 2012. The Company includes any step rents, fixed escalations, and lease concessions in its computation of minimum lease payments.

As of December 31, 2014, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Other	Total
		(in millions)	
2015	$ 18	$ 7	$ 25
2016	13	7	20
2017	9	7	16
2018	4	6	10
2019	1	4	5
2020 and thereafter	3	11	14
Total	$ 48	$ 42	$ 90

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 November 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 December 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 2017. 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 Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2014, there were approximately 1,000 current and former employees of the Company participating in the stock option program. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. Stock options held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted stock options for 2,034,150 shares, 1,509,662 shares, and 1,269,725 shares, respectively. The weighted average grant-date fair value of stock options granted during 2014, 2013, and 2012, derived using the Black-Scholes stock option pricing model, was $2.20, $2.93, and $3.39, respectively.

The compensation cost and tax benefits related to the grant of Southern Company stock options to the Company's employees and the exercise of stock options are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. No cash proceeds are received by the Company upon the exercise of stock options. The amounts were not material for any year presented.

As of December 31, 2014, 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, 2014, 2013, and 2012 was $19 million, $16 million, and $34 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $7 million, $6 million, and $13 million for the years ended December 31, 2014, 2013, and 2012, respectively. As of December 31, 2014, the aggregate intrinsic value for the options outstanding and options exercisable was $73 million and $51 million, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount. Performance share units held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted performance share units of 176,224, 161,240, and 152,812, respectively. The weighted average grant-date fair value of performance share units granted during 2014, 2013, and 2012, 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 $37.54, $40.50, and $41.99, respectively.

The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. For the years ended December 31, 2014, 2013, and 2012, total compensation cost for performance share units recognized in income was $6 million annually, with the related tax benefit of $2 million annually also recognized in income. The compensation cost and tax benefits related to the grant of Southern Company performance share units to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2014, there was $7 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 20 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 $13.6 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. On April 1, 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. 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 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 current maximum annual assessments for the Company under the NEIL policies would be $72 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, 2014, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 7	$ —	$ 7
Interest rate derivatives	—	6	—	6
Nuclear decommissioning trusts:[a]				
Domestic equity	180	2	—	182
Foreign equity	—	121	—	121
U.S. Treasury and government agency securities	—	96	—	96
Municipal bonds	—	62	—	62
Corporate bonds	—	188	—	188
Mortgage and asset backed securities	—	121	—	121
Other	11	8	—	19
Total	$ 191	$ 611	$ —	$ 802
Liabilities:				
Energy-related derivatives	$ —	$ 27	$ —	$ 27
Interest rate derivatives	—	14	—	14
Total	$ —	$ 41	$ —	$ 41

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

As of December 31, 2013, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2013:	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	$ —	$ 5	$ —	$ 5
Nuclear decommissioning trusts:[a]				
Domestic equity	197	1	—	198
Foreign equity	—	131	—	131
U.S. Treasury and government agency securities	—	79	—	79
Municipal bonds	—	64	—	64
Corporate bonds	—	140	—	140
Mortgage and asset backed securities	—	114	—	114
Other	—	24	—	24
Total	$ 197	$ 558	$ —	$ 755
Liabilities:				
Energy-related derivatives	$ —	$ 21	$ —	$ 21

(a) 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 financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally, implied volatility of interest rate options. See Note 11 for additional information on how these derivatives are used.

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' judgment, are also obtained when available.

As of December 31, 2014 and 2013, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2014:	*(in millions)*			
Nuclear decommissioning trusts:				
Foreign equity fund	$ 121	None	Monthly	5 days
Other — commingled funds	8	None	Daily	Not applicable
Other — money market funds	11	None	Daily	Not applicable
As of December 31, 2013:				
Nuclear decommissioning trusts:				
Foreign equity fund	$ 131	None	Daily	5 days
Corporate bonds — commingled funds	8	None	Daily	Not applicable
Other — commingled funds	24	None	Daily	Not applicable

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The foreign equity fund in the nuclear decommissioning trusts seeks to provide long-term capital appreciation. In pursuing this investment objective, the foreign equity fund primarily invests in a diversified portfolio of equity securities of foreign companies, including those in emerging markets. These equity securities may include, but are not limited to, common stocks, preferred stocks, real estate investment trusts, convertible securities, depositary receipts, including American depositary receipts, European depositary receipts, and global depositary receipts; and rights and warrants to buy common stocks. The Company may withdraw all or a portion of its investment on the last business day of each month subject to a minimum withdrawal of $1 million, provided that a minimum investment of $10 million remains. If notices of withdrawal exceed 20% of the aggregate value of the foreign equity fund, then the foreign equity fund's board may refuse to permit the withdrawal of all such investments and may scale down the amounts to be withdrawn pro rata and may further determine that any withdrawal that has been postponed will have priority on the subsequent withdrawal date.

The other-commingled funds and other-money market funds in the nuclear decommissioning trusts are invested primarily in a diversified portfolio of high quality, short-term, liquid debt securities. The funds represent the cash collateral received under the Funds' managers' securities lending program and/or the excess cash held within each separate investment account. The primary objective of the funds is to provide a high level of current income consistent with stability of principal and liquidity. The funds invest primarily in, but not limited to, commercial paper, floating and variable rate demand notes, debt securities issued or guaranteed by the U.S. government or its agencies or instrumentalities, time deposits, repurchase agreements, municipal obligations, notes, and other high-quality short-term liquid debt securities that mature in 90 days or less. Redemptions are available on a same day basis up to the full amount of the investment in the funds. See Note 1 under "Nuclear Decommissioning" for additional information.

As of December 31, 2014 and 2013, 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:		
2014	**$ 9,797**	**$ 10,552**
2013	$ 8,593	$ 8,782

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 offered 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 gross 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 commodity fuel prices and prices of electricity. The Company manages a fuel-hedging program, implemented per the guidelines of the Georgia PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in 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, 2014, the net volume of energy-related derivative contracts for natural gas positions totaled 46 million mmBtu, all of which expire by 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 expected volume of natural gas subject to such a feature is 4 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. 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, 2014, 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, 2014
	(in millions)				*(in millions)*
Cash Flow Hedges of Forecasted Debt					
	$ 350	3-month LIBOR	2.57%	May 2025	$ (6)
	350	3-month LIBOR	2.57%	November 2025	(2)
Cash Flow Hedges of Existing Debt					
	250	3-month LIBOR + 0.32%	0.75%	March 2016	—
	200	3-month LIBOR + 0.40%	1.01%	August 2016	—
Fair value hedges of existing debt					
	250	5.40%	3-month LIBOR + 4.02%	June 2018	(1)
	200	4.25%	3-month LIBOR + 2.46%	December 2019	—
Total	$ 1,600				$ (9)

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2015 are immaterial. The Company has deferred gains and losses related to interest rate derivative settlements of cash flow hedges that are expected to be amortized into earnings through 2037.

Derivative Financial Statement Presentation and Amounts

At December 31, 2014 and 2013, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	$ 6	$ 3	Liabilities from risk management activities	$ 23	$ 13
	Other deferred charges and assets	1	2	Other deferred credits and liabilities	4	8
Total derivatives designated as hedging instruments for regulatory purposes		$ 7	$ 5		$ 27	$ 21
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:	Other current assets	$ 5	$ —	Liabilities from risk management activities	$ 9	$ —
	Other deferred charges and assets	1	—	Other deferred credits and liabilities	5	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges		$ 6	$ —		$ 14	$ —
Total		$ 13	$ 5		$ 41	$ 21

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2014 and 2013.

The derivative contracts of the Company are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related 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. Amounts related to energy-related derivative contracts and interest rate derivative contracts at December 31, 2014 and 2013 are presented in the following tables.

	Fair Value					
Assets	**2014**	2013	**Liabilities**	**2014**	2013
	(in millions)			*(in millions)*	
Energy-related derivatives presented in the Balance Sheet [a]	$ 7	$ 5	Energy-related derivatives presented in the Balance Sheet [a]	$ 27	$ 21
Gross amounts not offset in the Balance Sheet [b]	(7)	(5)	Gross amounts not offset in the Balance Sheet [b]	(7)	(5)
Net energy-related derivative assets	$ —	$ —	**Net energy-related derivative liabilities**	$ 20	$ 16
Interest rate derivatives presented in the Balance Sheet [a]	$ 6	$ —	Interest rate derivatives presented in the Balance Sheet [a]	$ 14	$ —
Gross amounts not offset in the Balance Sheet [b]	(6)	—	Gross amounts not offset in the Balance Sheet [b]	(6)	—
Net interest rate derivative assets	$ —	$ —	**Net interest rate derivative liabilities**	$ 8	$ —

(a) The Company does not offset fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.

(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

At December 31, 2014 and 2013, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	Balance Sheet Location	2014	2013	Balance Sheet Location	2014	2013
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	$ (23)	$ (13)	Other regulatory liabilities, current	$ 6	$ 3
	Other regulatory assets, deferred	(4)	(8)	Other deferred credits and liabilities	1	2
Total energy-related derivative gains (losses)		$ (27)	$ (21)		$ 7	$ 5

For the year ended December 31, 2014, the pre-tax effect of interest rate derivatives designated as fair value hedging instruments on the statement of income was 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 statement of income was offset by changes to the carrying value of the long-term debt. The gains and losses related to interest rate derivative settlements of fair value hedges are recorded directly to earnings.

The pre-tax effects of interest rate derivatives designated as cash flow hedging instruments include $8 million of losses recognized in OCI for the year ended December 31, 2014 and amounts reclassified from accumulated OCI into earnings that were immaterial for all years presented.

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, 2014, the Company's collateral posted with its derivative counterparties was immaterial.

At December 31, 2014, the fair value of derivative liabilities with contingent features was $4 million. However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $54 million, and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

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

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

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2014 and 2013 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2014	**$ 2,269**	**$ 516**	**$ 266**
June 2014	**2,186**	**572**	**311**
September 2014	**2,631**	**920**	**525**
December 2014	**1,902**	**288**	**123**
March 2013	$ 1,882	$ 412	$ 197
June 2013	2,042	552	282
September 2013	2,484	872	487
December 2013	1,866	404	208

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

[This page intentionally left blank]

SELECTED FINANCIAL AND OPERATING DATA 2010-2014
Georgia Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in millions)	**$ 8,988**	$ 8,274	$ 7,998	$ 8,800	$ 8,349
Net Income After Dividends on Preferred and Preference Stock (in millions)	**$ 1,225**	$ 1,174	$ 1,168	$ 1,145	$ 950
Cash Dividends on Common Stock (in millions)	**$ 954**	$ 907	$ 983	$ 1,096	$ 820
Return on Average Common Equity (percent)	**12.24**	12.45	12.76	12.89	11.42
Total Assets (in millions)	**$ 31,030**	$ 28,907	$ 28,803	$ 27,151	$ 25,914
Gross Property Additions (in millions)	**$ 2,146**	$ 1,906	$ 1,838	$ 1,981	$ 2,401
Capitalization (in millions):					
Common stock equity	**$ 10,421**	$ 9,591	$ 9,273	$ 9,023	$ 8,741
Preferred and preference stock	**266**	266	266	266	266
Long-term debt	**8,683**	8,633	7,994	8,018	7,931
Total (excluding amounts due within one year)	**$ 19,370**	$ 18,490	$ 17,533	$ 17,307	$ 16,938
Capitalization Ratios (percent):					
Common stock equity	**53.8**	51.9	52.9	52.1	51.6
Preferred and preference stock	**1.4**	1.4	1.5	1.5	1.6
Long-term debt	**44.8**	46.7	45.6	46.4	46.8
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**2,102,673**	2,080,358	2,062,040	2,047,390	2,049,770
Commercial*	**301,246**	298,420	296,397	295,288	295,347
Industrial*	**9,132**	9,136	9,143	9,134	8,929
Other	**9,003**	8,623	7,724	7,521	7,309
Total	**2,422,054**	2,396,537	2,375,304	2,359,333	2,361,355
Employees (year-end)	**7,909**	7,886	8,094	8,310	8,330

* A reclassification of customers from commercial to industrial is reflected for years 2010-2013 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 2010-2014 (continued)
Georgia Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in millions):					
Residential	$ 3,350	$ 3,058	$ 2,986	$ 3,241	$ 3,072
Commercial	3,271	3,077	2,965	3,217	3,011
Industrial	1,525	1,391	1,322	1,547	1,441
Other	94	94	89	94	84
Total retail	8,240	7,620	7,362	8,099	7,608
Wholesale — non-affiliates	335	281	281	341	380
Wholesale — affiliates	42	20	20	32	53
Total revenues from sales of electricity	8,617	7,921	7,663	8,472	8,041
Other revenues	371	353	335	328	308
Total	$ 8,988	$ 8,274	$ 7,998	$ 8,800	$ 8,349
Kilowatt-Hour Sales (in millions):					
Residential	27,132	25,479	25,742	27,223	29,433
Commercial	32,426	31,984	32,270	32,900	33,855
Industrial	23,549	23,087	23,089	23,519	23,209
Other	633	630	641	657	663
Total retail	83,740	81,180	81,742	84,299	87,160
Wholesale — non-affiliates	4,323	3,029	2,934	3,904	4,662
Wholesale — affiliates	1,117	496	600	626	1,000
Total	89,180	84,705	85,276	88,829	92,822
Average Revenue Per Kilowatt-Hour (cents):					
Residential	12.35	12.00	11.60	11.91	10.44
Commercial	10.09	9.62	9.19	9.78	8.89
Industrial	6.48	6.03	5.73	6.58	6.21
Total retail	9.84	9.39	9.01	9.61	8.73
Wholesale	6.93	8.54	8.52	8.23	7.65
Total sales	9.66	9.35	8.99	9.54	8.66
Residential Average Annual Kilowatt-Hour Use Per Customer	12,969	12,293	12,509	13,288	14,367
Residential Average Annual Revenue Per Customer	$ 1,605	$ 1,475	$ 1,451	$ 1,582	$ 1,499
Plant Nameplate Capacity Ratings (year-end) (megawatts)	17,593	17,586	17,984	16,588	15,992
Maximum Peak-Hour Demand (megawatts):					
Winter	16,308	12,767	14,104	14,800	15,614
Summer	15,777	15,228	16,440	16,941	17,152
Annual Load Factor (percent)	61.2	63.5	59.1	59.5	60.9
Plant Availability (percent)*:					
Fossil-steam	86.3	87.1	90.3	88.6	88.6
Nuclear	90.8	91.8	94.1	92.2	94.0
Source of Energy Supply (percent):					
Coal	30.9	26.4	26.6	44.4	51.8
Nuclear	16.7	17.7	18.3	16.6	16.4
Hydro	1.3	2.0	0.7	1.1	1.4
Oil and gas	26.3	29.6	22.0	8.9	8.0
Purchased power —					
From non-affiliates	3.8	3.3	6.8	6.1	5.2
From affiliates	21.0	21.0	25.6	22.9	17.2
Total	100.0	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

[This page intentionally left blank]

GULF POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Gulf Power Company 2014 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, 2014.

S. W. Connally, Jr.
President and Chief Executive Officer

Richard S. Teel
Vice President and Chief Financial Officer
March 2, 2015

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, 2014 and 2013, 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, 2014. 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-307 to II-345) present fairly, in all material respects, the financial position of Gulf Power Company as of December 31, 2014 and 2013, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
March 2, 2015

DEFINITIONS

Term	Meaning
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ASC	Accounting Standards Codification
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GAAP	Generally accepted accounting principles
Georgia Power	Georgia Power Company
IRS	Internal Revenue Service
ITC	Investment tax credit
KWH	Kilowatt-hour
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
OCI	Other comprehensive income
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
ROE	Return on equity
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
scrubber	Flue gas desulfurization system
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
Southern Company system	The Southern Company, the traditional operating companies, Southern Power, Southern Electric Generating Company, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional operating companies	Alabama Power, Georgia Power, Gulf Power Company, and Mississippi Power

OVERVIEW

Business Activities

Gulf Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, restoration following major storms, and fuel. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

In December 2013, the Florida PSC voted to approve the settlement agreement (Settlement Agreement) among the Company and all of the intervenors to the docketed proceeding with respect to the Company's request to increase retail base rates. Under the terms of the Settlement Agreement, the Company (1) increased base rates designed to produce an additional $35 million in annual revenues effective January 2014 and subsequently increased base rates designed to produce an additional $20 million in annual revenues effective January 2015; (2) continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); (3) may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017; and (4) will accrue a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until the next base rate adjustment date or January 1, 2017, whichever comes first. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Retail Base Rate Case" herein for additional details of the Settlement Agreement.

Key Performance Indicators

The Company continues to focus on several key performance indicators including customer satisfaction, plant availability, system reliability, and net income after dividends on preference stock. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys to evaluate the Company's results and generally targets the top quartile of these surveys in measuring performance, which the Company achieved in 2014.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The Company's 2014 Peak Season EFOR of 0.98% was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The Company's performance for 2014 was better than the target for these transmission and distribution reliability measures.

The Company uses net income after dividends on preference stock as the primary measure of the Company's financial performance. In 2014, the Company achieved its targeted net income after dividends on preference stock. See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance.

Earnings

The Company's 2014 net income after dividends on preference stock was $140.2 million, representing a $15.8 million, or 12.7%, increase over the previous year. The increase was primarily due to higher retail revenues, partially offset by higher other operations and maintenance expenses as compared to the corresponding period in 2013.

In 2013, net income after dividends on preference stock was $124.4 million, representing a $1.5 million, or 1.2%, decrease from the previous year. The decrease was primarily due to an increase in depreciation and dividends on preference stock, partially offset by decreases in other operations and maintenance expenses and interest expense as compared to the corresponding period in 2012.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2014	2014	2013
		(in millions)	
Operating revenues	$ 1,590.5	$ 150.2	$ 0.6
Fuel	604.6	71.8	(12.1)
Purchased power	107.2	21.9	11.2
Other operations and maintenance	341.2	31.4	(4.3)
Depreciation and amortization	145.0	(4.0)	8.0
Taxes other than income taxes	111.2	12.8	1.0
Total operating expenses	1,309.2	133.9	3.8
Operating income	281.3	16.3	(3.2)
Total other income and (expense)	(44.0)	9.2	3.7
Income taxes	88.1	8.4	0.5
Net income	149.2	17.1	—
Dividends on preference stock	9.0	1.3	1.5
Net income after dividends on preference stock	$ 140.2	$ 15.8	$ (1.5)

Operating Revenues

Operating revenues for 2014 were $1.59 billion, reflecting an increase of $150.2 million from 2013. The following table summarizes the significant changes in operating revenues for the past two years:

	Amount	
	2014	2013
	(in millions)	
Retail — prior year	$ 1,170.0	$ 1,144.5
Estimated change resulting from –		
Rates and pricing	47.1	0.1
Sales growth (decline)	8.2	(1.4)
Weather	9.4	(0.3)
Fuel and other cost recovery	31.8	27.1
Retail — current year	1,266.5	1,170.0
Wholesale revenues –		
Non-affiliates	129.2	109.4
Affiliates	130.1	99.6
Total wholesale revenues	259.3	209.0
Other operating revenues	64.7	61.3
Total operating revenues	$ 1,590.5	$ 1,440.3
Percent change	10.4%	—%

In 2014, retail revenues increased $96.5 million, or 8.3%, when compared to 2013 primarily as a result of higher fuel cost recovery revenues and higher revenues resulting from an increase in retail base rates effective January 2014, as approved by the Florida PSC. In 2013, retail revenues increased $25.5 million, or 2.2%, when compared to 2012 primarily as a result of higher fuel revenues and energy conservation cost recovery revenues. The increase in fuel revenues was partially offset by a payment received during 2013 pursuant to the resolution of a coal contract dispute. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (or decline) and weather.

In 2014, revenues associated with changes in rates and pricing included higher revenues due to an increase in retail base rates and revenues associated with higher rates under the Company's environmental cost recovery clause. In 2013, revenues associated with changes in rates and pricing were relatively flat as a result of higher revenues due to increases in retail base rates, partially offset by lower rates under the Company's energy conservation cost recovery clause and the environmental cost recovery clause. Annually, the Company petitions the Florida PSC for recovery of projected 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:

	2014	2013	2012
		(in millions)	
Capacity and other	**$ 65.1**	$ 64.0	$ 68.2
Energy	**64.1**	45.4	38.7
Total non-affiliated	**$ 129.2**	$ 109.4	$ 106.9

Wholesale revenues from sales to non-affiliates consist of long-term sales agreements to other utilities in Florida and Georgia and short-term opportunity sales. Capacity revenues from long-term sales agreements represent the greatest contribution to net income. The energy is generally sold at variable cost. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost of energy. Wholesale energy revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. See FUTURE EARNINGS POTENTIAL – "General" for additional information.

In 2014, wholesale revenues from sales to non-affiliates increased $19.8 million, or 18.1%, as compared to the prior year primarily due to a 43.7% increase in KWH sales as a result of lower-priced energy supply alternatives from the Southern Company system's resources and fewer planned outages at Plant Scherer Unit 3 partially offset by a 1.9% decrease in the price of energy sold to non-affiliates due to the lower cost of fuel per KWH generated. In 2013, wholesale revenues from sales to non-affiliates increased $2.5 million, or 2.3%, as compared to the prior year primarily due to an 18.9% increase in KWH sales as a result of more energy scheduled by wholesale customers to serve their loads. This increase was partially offset by a 6.2% decrease in capacity revenues reflecting contractual reductions for changes in environmental costs.

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 2014, wholesale revenues from sales to affiliates increased $30.5 million, or 30.7%, as compared to the prior year primarily due to a 24.5% increase in the price of energy sold to affiliates due to higher marginal generation costs and a 5.0% increase in KWH sales as a result of an increase of the Company's generation dispatched to serve affiliated companies' higher weather-related energy demand primarily in the first and third quarters of 2014. In 2013, wholesale revenues from sales to affiliates decreased $24.1 million, or 19.5%, as compared to the prior year primarily due to lower energy revenues related to a 28.4% decrease in KWH sales that resulted from less Company generation being dispatched to serve affiliated companies' demand. This decrease in 2013 was partially offset by a 12.7% increase in the price of energy sold to affiliates in 2013.

Other operating revenues increased $3.4 million, or 5.5%, in 2014 as compared to the prior year primarily due to a $4.5 million increase in franchise fees due to increased retail revenues, partially offset by a $2.3 million decrease in revenues from other energy services. In 2013, other operating revenues decreased $3.4 million, or 5.3%, as compared to the prior year primarily due to a $5.4 million decrease in revenues from other energy services, partially offset by a $1.9 million increase in transmission

revenues. 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 2014 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2014	2014	2013	2014	2013
	(in millions)				
Residential	5,363	5.4%	0.7 %	1.3%	0.5 %
Commercial	3,838	0.7	(1.3)	0.1	(0.4)
Industrial	1,849	8.8	(1.4)	8.8	(1.4)
Other	25	20.5	(17.1)	20.5	(17.1)
Total retail	11,075	4.3	(0.4)	2.1%	(0.2)%
Wholesale					
Non-affiliates	1,670	43.7	18.9		
Affiliates	3,284	5.0	(28.4)		
Total wholesale	4,954	15.5	(19.8)		
Total energy sales	16,029	7.5%	(6.9)%		

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.

Residential KWH sales increased in 2014 compared to 2013 primarily due to colder weather in the first quarter of 2014 and customer growth. Residential KWH sales increased in 2013 compared to 2012 primarily due to customer growth.

Commercial KWH sales increased in 2014 compared to 2013 primarily due to colder weather in the first quarter of 2014 and customer growth, partially offset by a decline in weather-adjusted use per customer. Commercial KWH sales decreased in 2013 compared to 2012 primarily due to milder weather in 2013 compared to 2012 and a decline in weather-adjusted use per customer, partially offset by customer growth.

Industrial KWH sales increased in 2014 compared to 2013 primarily due to decreased customer co-generation and changes in customers' operations. Industrial KWH sales decreased in 2013 compared to 2012 primarily 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:

	2014	2013	2012
Total generation *(millions of KWHs)*	**11,109**	9,216	9,648
Total purchased power *(millions of KWHs)*	**5,547**	6,298	6,952
Sources of generation *(percent)* –			
Coal	**67**	61	60
Gas	**33**	39	40
Cost of fuel, generated *(cents per net KWH)* –			
Coal[a]	**4.03**	4.12	4.42
Gas	**3.93**	3.95	3.96
Average cost of fuel, generated *(cents per net KWH)*[a]	**3.99**	4.05	4.23
Average cost of purchased power *(cents per net KWH)*[b]	**4.83**	3.88	3.03

(a) 2013 cost of coal includes the effect of a payment received pursuant to the resolution of a coal contract dispute.
(b) Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

In 2014, total fuel and purchased power expenses were $711.8 million, an increase of $93.7 million, or 15.2%, from the prior year costs. Total fuel and purchased power expenses for 2013 included a 2013 payment received pursuant to the resolution of a coal contract dispute. Excluding the payment, the higher volume of KWHs generated and purchased increased expenses $54.9 million primarily due to increased Company owned generation dispatched to serve higher Southern Company system demand as a result of colder weather in the first quarter and warmer weather in the third quarter 2014. The increased expenses also included an $18.3 million increase due to a higher average cost of fuel and purchased power.

In 2013, total fuel and purchased power expenses were $618.1 million, a decrease of $0.9 million, or 0.2%, from the prior year costs. The decrease in fuel and purchased power expenses was due to a $37.3 million decrease in the volume of KWHs generated and purchased, partially offset by a $36.4 million increase in the average cost of fuel and purchased power which included a payment received during 2013 pursuant to the resolution of a coal contract dispute. Excluding the payment, the average cost of fuel and purchased power increased $57.0 million.

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 cost, purchased power capacity 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 $604.6 million in 2014, an increase of $71.8 million, or 13.5%, from the prior year costs. The increase was primarily due to a 20.5% higher volume of KWHs generated primarily due to increased generation dispatched to serve higher Southern Company system loads due to colder weather in the first quarter 2014 and warmer weather in the third quarter 2014. The fuel expense for 2013 included a 2013 payment received pursuant to the resolution of a coal contract dispute. Excluding the payment, the average cost of fuel per KWH generated decreased 6.8%. In 2013, fuel expense was $532.8 million, a decrease of $12.1 million, or 2.2%, from the prior year costs. The decrease was primarily due to a 4.3% decrease in the average cost of fuel per KWH generated which included a 2013 payment received pursuant to the resolution of a coal contract dispute. Excluding the payment, the average cost of fuel per KWH generated increased 1.2%.

Purchased Power – Non-Affiliates

Purchased power expense from non-affiliates was $82.0 million in 2014, an increase of $29.6 million, or 56.3%, from the prior year. The increase was due to a 37.3% increase in the average cost per KWH purchased, which included a $28.4 million increase in capacity costs associated with a scheduled price increase for an existing PPA, partially offset by the expiration of another PPA. This increase was partially offset by a 16.3% decrease in the volume of KWHs purchased due to colder regional weather conditions in the first quarter 2014 which limited the availability of market resources. In 2013, purchased power expense from non-affiliates was $52.4 million, an increase of $1.0 million, or 2.0%, from the prior year. The increase was due to a 31.5% increase in the average cost per KWH purchased, partially offset by a 13.8% decrease in the volume of KWHs purchased.

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

Purchased Power – Affiliates

Purchased power expense from affiliates was $25.2 million in 2014, a decrease of $7.7 million, or 23.1%, from the prior year. The decrease was primarily due to a 43.3% decrease in the average cost per KWH purchased, which included a $13.5 million reduction in capacity costs primarily associated with the expiration of an existing PPA. This decrease was partially offset by a 33.2% increase in the volume of KWHs purchased primarily due to higher planned outages for the Company's generating units in the fourth quarter 2014. In 2013, purchased power expense from affiliates was $32.9 million, an increase of $10.2 million, or 44.9%, from the prior year. The increase was primarily due to a 93.4% increase in the volume of KWHs purchased, partially offset by a 30.2% decrease in the average cost per KWH purchased.

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 2014, other operations and maintenance expenses increased $31.4 million, or 10.1%, compared to the prior year primarily due to increases in routine and planned maintenance expenses at generation, transmission and distribution facilities.

In 2013, other operations and maintenance expenses decreased $4.3 million, or 1.4%, compared to the prior year primarily due to decreases of $14.4 million in routine and planned maintenance expenses at generation facilities related to decreases in scheduled outages and cost containment efforts in 2013 and $4.9 million in other energy services expenses, partially offset by increases of $5.1 million in pension and other benefit-related expenses, $4.9 million in transmission service related to a third party PPA, $2.2 million in distribution system maintenance primarily due to increased vegetation management and $2.1 million in marketing incentive programs. Expenses from other energy services did not have a significant impact on earnings since they were generally offset by associated revenues. Expenses from transmission service did not have a significant impact on earnings since this expense was offset by purchased power capacity revenues through the Company's purchased power capacity recovery clause. Expenses from marketing incentive programs did not have a significant impact on earnings since the expense was offset by energy conservation revenues through the Company's energy conservation cost recovery clause. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Cost Recovery Clauses," and Notes 1 and 3 to the financial statements under "Affiliate Transactions" and "Cost Recovery Clauses," respectively, for additional information.

Depreciation and Amortization

Depreciation and amortization decreased $4.0 million, or 2.7%, in 2014 compared to the prior year. As authorized by the Florida PSC in the Settlement Agreement, the Company recorded an $8.4 million reduction in depreciation expense in 2014. This decrease was partially offset by increases of $4.4 million in depreciation and amortization primarily attributable to property additions at generation, transmission, and distribution facilities. In 2013, depreciation and amortization increased $8.0 million, or 5.7%, compared to the prior year primarily attributable to equipment replacements completed on Plant Crist Unit 7 and other additions to transmission and distribution facilities. See Note 3 to the financial statements under "Retail Regulatory Matters – Retail Base Rate Case" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $12.8 million, or 13.0%, in 2014 compared to the prior year primarily due to increases of $4.4 million in franchise fees and $4.0 million in gross receipts taxes as a result of higher retail revenues as well as a $2.7 million increase in property taxes. In 2013, taxes other than income taxes increased $1.0 million, or 1.1%, compared to the prior year primarily due to a $2.8 million increase in property taxes, partially offset by decreases of $0.7 million in gross receipts taxes, $0.7 million in payroll taxes, and $0.4 million in franchise fees. Gross receipts taxes and franchise fees have no impact on net income.

Allowance for Equity Funds Used During Construction

AFUDC equity increased $5.6 million, or 86.4%, in 2014 compared to the prior year primarily due to increased construction projects related to environmental control projects at generation facilities and transmission projects. In 2013, AFUDC equity increased $1.2 million, or 23.5%, compared to the prior year primarily due to increased construction projects related to environmental control projects at generation facilities. See Note 1 to the financial statements under "Allowance for Funds Used During Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized decreased $2.8 million, or 5.0%, in 2014 compared to the prior year primarily due to an increase in capitalization of AFUDC debt related to the construction of environmental control projects and lower interest rates on pollution control bonds, offset by increases in long term debt resulting from the issuance of additional senior notes in 2014. In 2013, interest expense, net of amounts capitalized decreased $4.2 million, or 7.0%, compared to the prior year primarily due to lower interest rates on pollution control bonds, senior notes, and customer deposits.

Income Taxes

Income taxes increased $8.4 million, or 10.5%, in 2014 compared to the prior year primarily due to higher pre-tax earnings. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Effects of Inflation

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

FUTURE EARNINGS POTENTIAL

General

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

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, the rate of economic growth or decline in the Company's service territory, and the successful remarketing of wholesale capacity as current contracts expire. Changes in regional and global economic conditions may impact sales for the Company, as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

The Company's wholesale business consists of two types of agreements. The first type, referred to as requirements service, provides that the Company serves the customer's capacity and energy requirements from other Company resources. The second type, referred to as a unit sale, is a wholesale customer purchase from a dedicated generating plant unit where a portion of that unit is reserved for the customer. These agreements are associated with the Company's co-ownership of a unit with Georgia Power at Plant Scherer and consist of both capacity and energy sales. Capacity revenues represent the majority of the Company's wholesale earnings. The Company currently has long-term sales agreements for 100% of the Company's ownership of that unit for 2015 and 41% for the next five years. These capacity revenues represented 82% of total wholesale capacity revenues for 2014. The Company is actively pursuing replacement wholesale contracts but the expiration of current contracts could have a material negative impact on the Company's earnings. In the event some portion of the Company's ownership in Plant Scherer is not subject to a replacement long-term wholesale contract, the proportionate amount of the unit may be sold into the power pool or into the wholesale market.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be recovered in retail rates or through long-term wholesale agreements on a timely basis or through market-based contracts. The State of Florida has statutory provisions that allow a utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. The Company's current long-term wholesale agreements contain provisions that permit charging the customer with costs incurred as a

result of changes in environmental laws and regulations. The full impact of any such regulatory or legislative changes cannot be determined at this time. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. 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 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.

Subsequent to December 31, 2014, the Company announced plans to retire its coal-fired generation at Plant Smith Units 1 and 2 (357 MWs) by March 31, 2016. The plant will continue to operate and produce electricity with its other generating units on site. The cost to comply with environmental regulations imposed by the EPA led to the decision to close these units. The retirement of these units is not expected to have a material impact on the Company's financial statements. The Company expects to recover through its rates the remaining book value of the retired units and certain costs associated with the retirements; however, recovery will be considered by the Florida PSC in future rate proceedings. The net book value of these units at December 31, 2014 was approximately $80 million.

The Company has also determined it is not economical to add the environmental controls at Plant Scholz necessary to comply with the Mercury and Air Toxics Standards (MATS) rule and that coal-fired generation at Plant Scholz (92 MWs) will cease by April 2015. The plant is scheduled to be fully depreciated by April 2015.

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against Georgia Power alleging violations of the New Source Review provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by the Company. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. See Note 3 to the financial statements under "Environmental Matters – New Source Review Actions" for additional information. The ultimate outcome of these matters cannot be determined at this time.

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; 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 2014, the Company had invested approximately $1.8 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $227 million, $143 million, and $70 million for 2014, 2013, and 2012, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $204 million from 2015 through 2017, with annual totals of approximately $127 million, $39 million, and $38 million for 2015, 2016, and 2017, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information.

The Company'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 and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company has spent approximately $1.4 billion in reducing and monitoring emissions pursuant to the Clean Air

Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2012, the EPA finalized the MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015, up to April 16, 2016 for affected units for which extensions have been granted. On November 25, 2014, the U.S. Supreme Court granted a petition for review of the final MATS rule.

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 more stringent eight-hour ozone NAAQS, which it began to implement in 2011. In 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone NAAQS. All areas within the Company's service territory have achieved attainment of this standard. On December 17, 2014, the EPA published a proposed rule to further reduce the current eight-hour ozone standard. The EPA is required by federal court order to complete this rulemaking by October 1, 2015. Finalization of a lower eight-hour ozone standard could result in the designation of new ozone nonattainment areas within the Company's service territory.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS. In 2012, the EPA issued a final rule that increases the stringency of the annual fine particulate matter standard. The EPA promulgated final designations for the 2012 annual standard on December 18, 2014, and no new nonattainment areas were designated within the Company's service territory. The EPA has, however, deferred designation decisions for certain areas in Florida, so future nonattainment designations in these areas are possible.

Final revisions to the NAAQS for sulfur dioxide (SO_2), which established a new one-hour standard, became effective in 2010. No areas within the Company's service territory have been designated as nonattainment under this rule. However, the EPA has announced plans to make additional designation decisions for SO_2 in the future, which could result in nonattainment designations for areas within the Company's service territory. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

The Company's service territory is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I beginning in 2015 and Phase II beginning in 2017. In 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety, but on April 29, 2014, the U.S. Supreme Court overturned that decision and remanded the case back to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The U.S. Court of Appeals for the District of Columbia Circuit granted the EPA's motion to lift the stay of the rule, and the first phase of CSAPR took effect on January 1, 2015.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology to certain sources, including fossil fuel-fired generating facilities, built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter.

In 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units), during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

In February 2013, the EPA proposed a rule that would require certain states to revise 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). The EPA proposed to supplement the 2013 proposed rule on September 17, 2014, making it more stringent. The EPA has entered into a settlement agreement requiring it to finalize the proposed rule by May 22, 2015. The proposed rule would require states subject to the rule (including Florida, Georgia, and Mississippi) to revise their SSM provisions within 18 months after issuance of the final 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. As part of this strategy, the Company has developed a compliance plan for the MATS rule which includes reliance on existing emission control technologies, the use of existing or additional natural gas capability, and unit retirements. Additionally, certain transmission system upgrades are required. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, CSAPR, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of

the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. These regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition.

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 on October 14, 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

In June 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing revised technology-based limits for certain wastestreams from steam electric power plants and best management practices for CCR surface impoundments. The EPA has entered into a consent decree requiring it to finalize revisions to the steam electric effluent guidelines by September 30, 2015. The ultimate impact of the rule will also depend on the specific technology requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

On April 21, 2014, the EPA and the U.S. Army Corps of Engineers jointly published a proposed rule to revise the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs, which would significantly expand the scope of federal jurisdiction under the CWA. In addition, the rule as proposed could have significant impacts on economic development projects which could affect customer demand growth. The ultimate impact of the proposed rule will depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time. If finalized as proposed, 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.

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 proposed and final water quality regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition.

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 part owner of units at generating plants located in Mississippi and Georgia operated by the respective unit's co-owner. In addition to on-site storage, the Company sells a portion of its CCR to third parties for beneficial reuse. Individual states regulate CCR and the States of Florida, Georgia, and Mississippi each have their own regulatory requirements. The Company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate 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 mandate 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 mandated closure of a CCR Unit. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $62 million and ongoing post-closure care of approximately $11 million. The Company has previously recorded asset retirement obligations (ARO) associated with ash ponds of $6 million, or $11 million on a nominal dollar basis, based on existing state requirements. During 2015, the Company will record AROs for any incremental estimated closure costs resulting from acceleration in the timing of any currently planned closures and for differences

between existing state requirements and the requirements of the CCR Rule. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

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 properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known impacted sites. Included in this amount are costs associated with remediation of the Company's substation sites. These projects have been approved by the Florida PSC for recovery through the environmental cost recovery clause; therefore, these liabilities have no impact to the Company's net income. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

In 2014, the EPA published three sets of proposed standards that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. On January 8, 2014, the EPA published proposed standards for new units, and, on June 18, 2014, the EPA published proposed standards governing existing units, known as the Clean Power Plan, and separate standards governing CO_2 emissions from modified and reconstructed units. The EPA's proposed Clean Power Plan establishes guidelines for states to develop plans to address CO_2 emissions from existing fossil fuel-fired electric generating units. The EPA's proposed guidelines establish state-specific interim and final CO_2 emission rate goals to be achieved between 2020 and 2029 and 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. 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 market-based contracts.

The Southern Company system filed comments on the EPA's proposed Clean Power Plan on December 1, 2014. These comments addressed legal and technical issues in addition to providing a preliminary estimated cost of complying with the proposed guidelines utilizing one of the EPA's compliance scenarios. Costs associated with this proposal could be significant to the utility industry and the Southern Company system. However, the ultimate financial and operational impact of the proposed Clean Power Plan on the Southern Company system cannot be determined at this time and will depend upon numerous known and unknown factors. Some of the unknown factors include: the structure, timing, and content of the EPA's final guidelines; individual state implementation of these guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

Over the past several years, the U.S. Congress has also considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2013 greenhouse gas emissions were approximately 8 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2014 greenhouse gas emissions on the same basis is approximately 10 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.

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Retail Base Rate Case

In December 2013, the Florida PSC voted to approve the Settlement Agreement among the Company and all of the intervenors to the docketed proceeding with respect to the Company's request to increase retail base rates. Under the terms of the Settlement Agreement, the Company (1) increased base rates designed to produce an additional $35 million in annual revenues effective January 2014 and subsequently increased base rates designed to produce an additional $20 million in annual revenues effective January 2015; (2) continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); and (3) will accrue a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until the next base rate adjustment date or January 1, 2017, whichever comes first.

The Settlement Agreement also provides that the Company may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017. In any given month, such depreciation expense reduction may not exceed the amount necessary for the ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized ROE range then in effect. Recovery of the regulatory asset will occur over a period to be determined by the Florida PSC in the Company's next base rate case or next depreciation and dismantlement study proceeding, whichever comes first. The Company recognized an $8.4 million reduction in depreciation expense in 2014.

Cost Recovery Clauses

On October 22, 2014, the Florida PSC approved the Company's annual rate clause request for its fuel, purchased power capacity, environmental, and energy conservation cost recovery factors for 2015. The net effect of the approved changes is an expected $41.2 million increase in annual revenue for 2015. The increased revenues will not have a significant impact on net income since most of the revenues will be offset by expenses.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment. See Note 1 to the financial statements under "Revenues" for additional information.

Income Tax Matters

Bonus Depreciation

On December 19, 2014, the Tax Increase Prevention Act of 2014 (TIPA) was signed into law. The TIPA retroactively extended several tax credits through 2014 and extended 50% bonus depreciation for property placed in service in 2014 (and for certain long-term production-period projects to be placed in service in 2015). The extension of 50% bonus depreciation had a positive impact on the Company's cash flows and, combined with bonus depreciation allowed in 2014 under the American Taxpayer Relief Act of 2012, resulted in approximately $25 million of positive cash flows for the 2014 tax year. The estimated cash flow benefit of bonus depreciation related to TIPA is expected to be approximately $65 million to $70 million for the 2015 tax year.

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.

Electric Utility Regulation

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

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

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, in accordance with GAAP, 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 financial position, results of operations, or cash flows.

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 in accordance with GAAP 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 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. The Company discounts the future cash flows related to its postretirement benefit plans 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 purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased

the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $29.6 million and $2.6 million, respectively. The adoption of new mortality tables will increase net periodic costs related to the Company's pension plans and other postretirement benefit plans in 2015 by $3.9 million and $0.1 million, respectively.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $1.6 million or less change in total annual benefit expense and a $22.0 million or less change in projected obligations.

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2014. 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 comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2015 through 2017, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period are primarily to maintain existing generation facilities, to add environmental equipment for existing generating units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances and through equity contributions from Southern Company. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as 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 increased in value as of December 31, 2014 as compared to December 31, 2013. In December 2014, the Company voluntarily contributed $30.0 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. See Note 2 to the financial statements under "Pension Plans" for additional information.

Net cash provided from operating activities totaled $343.1 million in 2014, an increase of $13.4 million from 2013, primarily due to changes in cash flows related to clause recovery and a decrease in fossil fuel stock. This increase was partially offset by decreases in cash flows associated with pension, post-retirement and other employee benefits, and deferred income taxes.

In 2013, net cash provided from operating activities totaled $329.7 million, a decrease of $89.5 million from 2012, primarily due to decreases in deferred income taxes related to bonus depreciation and lower recovery of fuel costs which moved from an over recovered to an under recovered position. These decreases were partially offset by increases in cash flow related to reductions in fossil fuel stock.

Net cash used for investing activities totaled $357.7 million, $306.6 million, and $348.6 million for 2014, 2013, and 2012, respectively. The changes in cash used for investing activities were primarily due to gross property additions to utility plant of $360.9 million, $304.8 million, and $325.2 million for 2014, 2013, and 2012, respectively. Funds for the Company's property additions were provided by operating activities, capital contributions, and other financing activities.

Net cash provided from financing activities totaled $31.5 million for 2014. Net cash used for financing activities totaled $33.6 million and $55.8 million for 2013 and 2012, respectively. The $65.1 million increase in cash from financing activities in 2014 was primarily due to the issuance of long-term debt and common stock, partially offset by the payment of common stock dividends, the redemption of long-term debt and a decrease to notes payable. The decreases of cash used in 2013 and 2012 were primarily for the payment of common stock dividends and redemptions of long-term debt, partially offset by issuances of stock to Southern Company and issuances of long-term debt. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2014 included increases of $231.3 million in property, plant, and equipment, primarily due to additions in generation, transmission, and distribution facilities, $211.4 million in long-term debt, $75.6 million in other regulatory assets, deferred, related to pension and other postretirement benefits, $55.7 million in other regulatory assets primarily related to an increase in contract hedges, $50.0 million in common stock issued to Southern Company, and $44.4 million in

employee benefit obligations as a result of changes in the actuarial assumptions. Decreases included $75.0 million in securities due within one year.

The Company's ratio of common equity to total capitalization, including short-term debt, was 44.6% in 2014 and 44.9% in 2013. 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, security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors.

Security issuances are subject to annual regulatory approval by the Florida PSC pursuant to its rules and regulations. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Florida PSC, as well as the amounts, if any, registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

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

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business. The Company has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet short-term liquidity needs, including its commercial paper program which is supported by bank credit facilities.

At December 31, 2014, the Company had approximately $38.6 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2014 were as follows:

Expires					Executable Term-Loans		Due Within One Year	
2015	2016	2017	Total	Unused	One Year	Two Years	Term Out	No Term Out
				(in millions)				
$80	$ 165	$30	$275	$275	$50	$—	$50	$30

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 default provisions to other indebtedness (including guarantee obligations) that are restricted only to the indebtedness 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 specified threshold. The Company is currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings. Subject to applicable market conditions, the Company expects to renew its bank credit arrangements as needed, prior to expiration.

Most of the unused credit arrangements with banks is allocated to provide liquidity support to the Company's variable rate 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, 2014 was approximately $69.3 million. At December 31, 2014, the Company had $78.0 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

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

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2014:					
Commercial paper	**$ 110**	**0.3%**	**$ 85**	**0.2%**	**$145**
December 31, 2013:					
Commercial paper	$ 136	0.2%	$ 92	0.2%	$173
Short-term bank debt	—	N/A	11	1.2%	125
Total	$ 136	0.2%	$ 103	0.3%	
December 31, 2012:					
Commercial paper	$ 124	0.3%	$ 69	0.3%	$124

(a) 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, and cash.

Financing Activities

In January 2014, the Company issued 500,000 shares of common stock to Southern Company and realized proceeds of $50.0 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

In April 2014, the Company executed a loan agreement with Mississippi Business Finance Corporation (MBFC) related to MBFC's issuance of $29.075 million aggregate principal amount of Pollution Control Revenue Refunding Bonds, First Series 2014 (Gulf Power Company Project) due April 1, 2044 for the benefit of the Company. The proceeds were used to redeem $29.075 million aggregate principal amount of MBFC Pollution Control Revenue Refunding Bonds, Series 2003 (Gulf Power Company Project).

In June 2014, the Company reoffered to the public $13 million aggregate principal amount of MBFC Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2012 (Gulf Power Company Project), which had been previously purchased and held by the Company since December 2013.

In September 2014, the Company issued $200 million aggregate principal amount of Series 2014A 4.55% Senior Notes due October 1, 2044. The proceeds were used to repay a portion of the Company's outstanding short-term indebtedness, for general corporate purposes, including the Company's continuous construction program, and for repayment at maturity $75 million aggregate principal amount of the Company's Series K 4.90% Senior Notes due October 1, 2014.

Subsequent to December 31, 2014, the Company issued 200,000 shares of common stock to Southern Company and realized proceeds of $20 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

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

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, and energy price risk management. The maximum potential collateral requirements under these contracts at December 31, 2014 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 74
Below BBB- and/or Baa3	447

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

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 $69.3 million of outstanding variable rate long-term debt that has not been hedged at January 1, 2015 was .02%. If the Company sustained a 100 basis point change in interest rates for all variable rate long-term debt, the change would affect annualized interest expense by approximately $0.7 million at January 1, 2015. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to movements in fuel and electricity prices, the Company enters into financial hedge contracts for natural gas purchases and physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. The Company continues to manage a fuel-hedging program implemented per the guidelines of the Florida PSC and the actual cost of fuel is recovered through the retail fuel clause. The Company had no material change in market risk exposure for the year ended December 31, 2014 when compared to the year ended December 31, 2013.

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:

	2014 Changes	2013 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$ (10)	$ (23)
Contracts realized or settled	(3)	13
Current period changes[a]	(59)	—
Contracts outstanding at the end of the period, assets (liabilities), net	$ (72)	$ (10)

(a) 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:

	2014	2013
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	**85**	87
Commodity – Natural gas options	**—**	2
Total hedge volume	**85**	89

The weighted average swap contract cost above market prices was approximately $0.80 per mmBtu as of December 31, 2014 and $0.12 per mmBtu as of December 31, 2013. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. Natural gas settlements are recovered through the Company's fuel cost recovery clause.

At December 31, 2014 and 2013, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery clause. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented and the actual cost of fuel is recovered through the retail fuel clause.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2014 were as follows:

	Fair Value Measurements December 31, 2014			
	Total Fair Value	Maturity		
		Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ —	$ —	$ —	$ —
Level 2	(72)	(37)	(33)	(2)
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ (72)	$ (37)	$ (33)	$ (2)

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

The construction program of the Company is currently estimated to be $263 million for 2015, $186 million for 2016, and $168 million for 2017. Capital expenditures to comply with environmental statutes and regulations included in these amounts are estimated to be $127 million, $39 million, and $38 million for 2015, 2016, and 2017, respectively. These amounts include capital expenditures related to contractual purchase commitments for capital expenditures covered under long-term service agreements. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" for additional information.

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts;

changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in the expected environmental compliance program; changes in FERC rules and regulations; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

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

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

Contractual Obligations

	2015	2016-2017	2018-2019	After 2019	Total
			(in thousands)		
Long-term debt[a] –					
Principal	$ —	$ 195,000	$ —	$1,183,955	$1,378,955
Interest	57,546	109,262	93,402	853,213	1,113,423
Financial derivative obligations[b]	36,934	32,938	2,563	—	72,435
Preference stock dividends[c]	9,003	18,006	18,006	—	45,015
Operating leases[d]	15,239	16,624	—	—	31,863
Unrecognized tax benefits[e]	46	—	—	—	46
Purchase commitments –					
Capital[f]	262,814	326,536	—	—	589,350
Fuel[g]	276,437	349,155	255,854	145,535	1,026,981
Purchased power[h]	92,395	183,929	182,929	315,331	774,584
Other[i]	16,498	20,616	15,820	43,145	96,079
Pension and other postretirement benefit plans[j]	4,716	10,061	—	—	14,777
Total	$771,628	$1,262,127	$568,574	$2,541,179	$5,143,508

(a) All amounts are reflected based on final maturity dates. The Company plans to continue 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, 2015, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

(b) For additional information, see Notes 1 and 10 to the financial statements.

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

(d) Excludes a PPA accounted for as a lease and is included in purchased power.

(e) See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(f) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with environmental regulations. These amounts exclude capital expenditures covered under long-term service agreements, which are reflected in Other. At December 31, 2014, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

(g) 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, 2014.

(h) The capacity and transmission related costs associated with PPAs are recovered through the purchased power capacity clause. See Notes 3 and 7 to the financial statements for additional information.

(i) 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.

(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 2014 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, access to sources of capital, projections for the qualified pension plan and postretirement benefit plan contributions, financing activities, start and completion of construction projects, filings with state and federal regulatory authorities, impact of the TIPA, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, CCR, and emissions of sulfur, nitrogen, CO_2, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including pending EPA civil action against the Company and IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any operational and environmental performance standards;
- investment performance of the Company's employee and retiree benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;

- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

[This page intentionally left blank]

STATEMENTS OF INCOME
For the Years Ended December 31, 2014, 2013, and 2012
Gulf Power Company 2014 Annual Report

	2014	2013	2012
		(in thousands)	
Operating Revenues:			
Retail revenues	$ **1,266,540**	$ 1,170,000	$ 1,144,471
Wholesale revenues, non-affiliates	**129,151**	109,386	106,881
Wholesale revenues, affiliates	**130,107**	99,577	123,636
Other revenues	**64,684**	61,338	64,774
Total operating revenues	**1,590,482**	1,440,301	1,439,762
Operating Expenses:			
Fuel	**604,641**	532,791	544,936
Purchased power, non-affiliates	**81,993**	52,443	51,421
Purchased power, affiliates	**25,246**	32,835	22,665
Other operations and maintenance	**341,214**	309,865	314,195
Depreciation and amortization	**145,026**	149,009	141,038
Taxes other than income taxes	**111,147**	98,355	97,313
Total operating expenses	**1,309,267**	1,175,298	1,171,568
Operating Income	**281,215**	265,003	268,194
Other Income and (Expense):			
Allowance for equity funds used during construction	**12,021**	6,448	5,221
Interest income	**90**	369	1,408
Interest expense, net of amounts capitalized	**(53,234)**	(56,025)	(60,250)
Other income (expense), net	**(2,851)**	(3,994)	(3,227)
Total other income and (expense)	**(43,974)**	(53,202)	(56,848)
Earnings Before Income Taxes	**237,241**	211,801	211,346
Income taxes	**88,062**	79,668	79,211
Net Income	**149,179**	132,133	132,135
Dividends on Preference Stock	**9,003**	7,704	6,203
Net Income After Dividends on Preference Stock	$ **140,176**	$ 124,429	$ 125,932

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2014, 2013, and 2012
Gulf Power Company 2014 Annual Report

	2014	2013	2012
		(in thousands)	
Net Income	**$ 149,179**	$ 132,133	$ 132,135
Other comprehensive income (loss):			
Qualifying hedges:			
Reclassification adjustment for amounts included in net income, net of tax of $234, $297, and $360, respectively	**372**	472	573
Total other comprehensive income (loss)	**372**	472	573
Comprehensive Income	**$ 149,551**	$ 132,605	$ 132,708

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2014, 2013, and 2012
Gulf Power Company 2014 Annual Report

	2014	2013	2012
		(in thousands)	
Operating Activities:			
Net income	$ **149,179**	$ 132,133	$ 132,135
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**152,670**	155,798	147,723
Deferred income taxes	**65,330**	77,069	174,305
Allowance for equity funds used during construction	**(12,021)**	(6,448)	(5,221)
Pension, postretirement, and other employee benefits	**(23,305)**	11,422	(8,109)
Stock based compensation expense	**1,928**	1,749	1,647
Other, net	**(1,233)**	5,865	4,518
Changes in certain current assets and liabilities —			
-Receivables	**(17,178)**	(49,051)	8,713
-Fossil fuel stock	**33,603**	19,468	(6,144)
-Materials and supplies	**(721)**	(1,570)	(3,035)
-Prepaid income taxes	**(19,179)**	15,526	355
-Other current assets	**(883)**	682	417
-Accounts payable	**8,279**	(6,964)	(5,195)
-Accrued taxes	**(1,924)**	(4,759)	(4,705)
-Accrued compensation	**11,237**	(3,309)	481
-Over recovered regulatory clause revenues	**—**	(17,092)	(10,858)
-Other current liabilities	**(2,704)**	(782)	(7,837)
Net cash provided from operating activities	**343,078**	329,737	419,190
Investing Activities:			
Property additions	**(348,305)**	(292,914)	(313,257)
Cost of removal net of salvage	**(12,932)**	(13,827)	(28,993)
Construction payables	**11,574**	6,796	1,161
Payments pursuant to long-term service agreements	**(8,012)**	(7,109)	(8,119)
Other investing activities	**(19)**	496	656
Net cash used for investing activities	**(357,694)**	(306,558)	(348,552)
Financing Activities:			
Increase (decrease) in notes payable, net	**(25,900)**	12,108	16,075
Proceeds —			
Common stock issued to parent	**50,000**	40,000	40,000
Capital contributions from parent company	**4,037**	2,987	2,106
Preference stock	**—**	50,000	—
Pollution control revenue bonds	**42,075**	63,000	13,000
Senior notes	**200,000**	90,000	100,000
Redemptions —			
Pollution control revenue bonds	**(29,075)**	(76,000)	(13,000)
Senior notes	**(75,000)**	(90,000)	(91,363)
Payment of preference stock dividends	**(9,003)**	(7,004)	(6,203)
Payment of common stock dividends	**(123,200)**	(115,400)	(115,800)
Other financing activities	**(2,457)**	(3,284)	(614)
Net cash provided from (used for) financing activities	**31,477**	(33,593)	(55,799)
Net Change in Cash and Cash Equivalents	**16,861**	(10,414)	14,839
Cash and Cash Equivalents at Beginning of Year	**21,753**	32,167	17,328
Cash and Cash Equivalents at End of Year	$ **38,614**	$ 21,753	$ 32,167
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $5,373, $3,421 and $2,500 capitalized, respectively)	$ **48,030**	$ 53,401	$ 58,255
Income taxes (net of refunds)	**44,125**	(10,727)	(96,639)
Noncash transactions — accrued property additions at year-end	**41,526**	31,546	27,369

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

BALANCE SHEETS
At December 31, 2014 and 2013
Gulf Power Company 2014 Annual Report

Assets	2014	2013
		(in thousands)
Current Assets:		
Cash and cash equivalents	$ 38,614	$ 21,753
Receivables —		
Customer accounts receivable	73,000	64,884
Unbilled revenues	58,268	57,282
Under recovered regulatory clause revenues	57,153	48,282
Other accounts and notes receivable	8,145	8,620
Affiliated companies	9,867	8,259
Accumulated provision for uncollectible accounts	(2,087)	(1,131)
Fossil fuel stock, at average cost	101,447	135,050
Materials and supplies, at average cost	55,656	54,935
Other regulatory assets, current	74,242	18,536
Prepaid expenses	39,673	33,186
Other current assets	1,711	6,120
Total current assets	515,689	455,776
Property, Plant, and Equipment:		
In service	4,494,953	4,363,664
Less accumulated provision for depreciation	1,295,714	1,211,336
Plant in service, net of depreciation	3,199,239	3,152,328
Construction work in progress	465,033	280,626
Total property, plant, and equipment	3,664,272	3,432,954
Other Property and Investments	15,148	15,314
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	55,931	50,597
Prepaid pension costs	—	11,533
Other regulatory assets, deferred	416,028	340,415
Other deferred charges and assets	41,191	30,982
Total deferred charges and other assets	513,150	433,527
Total Assets	$ 4,708,259	$ 4,337,571

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

BALANCE SHEETS
At December 31, 2014 and 2013
Gulf Power Company 2014 Annual Report

Liabilities and Stockholder's Equity	2014	2013
		(in thousands)
Current Liabilities:		
Securities due within one year	$ —	$ 75,000
Notes payable	**109,977**	135,878
Accounts payable —		
Affiliated	**87,397**	76,897
Other	**55,848**	47,038
Customer deposits	**35,094**	34,433
Accrued taxes —		
Accrued income taxes	**46**	45
Other accrued taxes	**9,201**	7,486
Accrued interest	**10,686**	10,272
Accrued compensation	**22,894**	11,657
Deferred capacity expense, current	**21,988**	—
Other regulatory liabilities, current	**566**	13,408
Liabilities from risk management activities	**36,934**	6,470
Other current liabilities	**22,386**	22,972
Total current liabilities	**413,017**	441,556
Long-Term Debt (See accompanying statements)	**1,369,594**	1,158,163
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**799,723**	734,355
Accumulated deferred investment tax credits	**2,783**	4,055
Employee benefit obligations	**120,752**	76,338
Deferred capacity expense	**163,077**	180,149
Other cost of removal obligations	**234,587**	228,148
Other regulatory liabilities, deferred	**48,556**	56,051
Other deferred credits and liabilities	**100,076**	77,126
Total deferred credits and other liabilities	**1,469,554**	1,356,222
Total Liabilities	**3,252,165**	2,955,941
Preference Stock (See accompanying statements)	**146,504**	146,504
Common Stockholder's Equity (See accompanying statements)	**1,309,590**	1,235,126
Total Liabilities and Stockholder's Equity	$ **4,708,259**	$ 4,337,571
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2014 and 2013
Gulf Power Company 2014 Annual Report

	2014	2013	2014	2013
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
4.90% due 2014	—	75,000		
5.30% due 2016	**110,000**	110,000		
5.90% due 2017	**85,000**	85,000		
3.10% to 5.75% due 2020-2051	**875,000**	675,000		
Total long-term notes payable	**1,070,000**	945,000		
Other long-term debt —				
Pollution control revenue bonds —				
0.55% to 6.00% due 2022-2049	**239,625**	226,625		
Variable rates (0.02% to 0.04% at 1/1/15) due 2022-2039	**69,330**	69,330		
Total other long-term debt	**308,955**	295,955		
Unamortized debt discount	**(9,361)**	(7,792)		
Total long-term debt (annual interest requirement — $57.5 million)	**1,369,594**	1,233,163		
Less amount due within one year	—	75,000		
Long-term debt excluding amount due within one year	**1,369,594**	1,158,163	**48.5%**	45.6%
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)	**53,886**	53,886		
— 6.45% preference stock — 450,000 shares (non-cumulative)	**44,112**	44,112		
— 5.60% preference stock — 500,000 shares (non-cumulative)	**48,506**	48,506		
Total preference stock (annual dividend requirement — $9.0 million)	**146,504**	146,504	**5.2**	5.8
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 20,000,000 shares				
Outstanding — 2014: 5,442,717 shares				
— 2013: 4,942,717 shares	**483,060**	433,060		
Paid-in capital	**559,797**	552,681		
Retained earnings	**267,470**	250,494		
Accumulated other comprehensive loss	**(737)**	(1,109)		
Total common stockholder's equity	**1,309,590**	1,235,126	**46.3**	48.6
Total Capitalization	**$ 2,825,688**	$ 2,539,793	**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, 2014, 2013, and 2012
Gulf Power Company 2014 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)			
Balance at December 31, 2011	4,143	$ 353,060	$ 542,709	$ 231,333	$ (2,154)	$ 1,124,948
Net income after dividends on preference stock	—	—	—	125,932	—	125,932
Issuance of common stock	400	40,000	—	—	—	40,000
Capital contributions from parent company	—	—	5,089	—	—	5,089
Other comprehensive income (loss)	—	—	—	—	573	573
Cash dividends on common stock	—	—	—	(115,800)	—	(115,800)
Balance at December 31, 2012	4,543	393,060	547,798	241,465	(1,581)	1,180,742
Net income after dividends on preference stock	—	—	—	124,429	—	124,429
Issuance of common stock	400	40,000	—	—	—	40,000
Capital contributions from parent company	—	—	4,883	—	—	4,883
Other comprehensive income (loss)	—	—	—	—	472	472
Cash dividends on common stock	—	—	—	(115,400)	—	(115,400)
Balance at December 31, 2013	**4,943**	**433,060**	**552,681**	**250,494**	**(1,109)**	**1,235,126**
Net income after dividends on preference stock	—	—	—	**140,176**	—	**140,176**
Issuance of common stock	**500**	**50,000**	—	—	—	**50,000**
Capital contributions from parent company	—	—	**7,116**	—	—	**7,116**
Other comprehensive income (loss)	—	—	—	—	**372**	**372**
Cash dividends on common stock	—	—	—	**(123,200)**	—	**(123,200)**
Balance at December 31, 2014	**5,443**	**$ 483,060**	**$ 559,797**	**$ 267,470**	**$ (737)**	**$ 1,309,590**

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

[This page intentionally left blank]

Index to the Notes to Financial Statements

Note		Page
1	Summary of Significant Accounting Polices	II-315
2	Retirement Benefits	II-321
3	Contingencies and Regulatory Matters	II-331
4	Joint Ownership Agreements	II-334
5	Income Taxes	II-334
6	Financing	II-337
7	Commitments	II-339
8	Stock Compensation	II-340
9	Fair Value Measurements	II-341
10	Derivatives	II-343
11	Quarterly Financial Information (Unaudited)	II-346

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Gulf Power Company (the Company) is a wholly-owned subsidiary of The Southern Company (Southern Company), which is the parent company of four traditional operating companies, as well as Southern Power, SCS, SouthernLINC Wireless, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, and other direct and indirect subsidiaries. The traditional operating companies – the Company, Alabama Power, Georgia Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers in northwest Florida and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants.

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

The Company is subject to regulation by the FERC and the Florida PSC. The Company follows GAAP in the U.S. and complies 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

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

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 $79.6 million, $78.4 million, and $95.9 million during 2014, 2013, and 2012, 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 $8.7 million, $10.2 million, and $6.9 million and Mississippi Power $30.5 million, $16.5 million, and $21.1 million in 2014, 2013, and 2012, respectively, for its proportionate share of related expenses. See Note 4 and Note 7 under "Operating Leases" for additional information.

The Company entered into a PPA with Southern Power for approximately 292 MWs annually from June 2009 through May 2014. Purchased power expenses associated with the PPA were $1.8 million, $14.2 million, and $14.7 million in 2014, 2013, and 2012, respectively, and fuel costs associated with the PPA were $1.7 million, $0.8 million, and $2.6 million in 2014, 2013, and 2012, respectively. These costs were approved for recovery by the Florida PSC through the Company's fuel and purchased power capacity cost recovery clauses. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

The Company had an agreement with Georgia Power under the transmission facility cost allocation tariff for delivery of power from the Company's resources in the state of Georgia. The Company reimbursed Georgia Power $1.0 million in 2014 and $2.4 million in each of the years 2013 and 2012 for its share of related expenses.

The Company has an agreement with Alabama Power under which Alabama Power has made transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA, which was entered into in 2009 for the capacity and energy from a combined cycle plant located in Autauga County, Alabama. Revenue requirement obligations to Alabama Power for these upgrades are estimated to be $132.0 million for the entire project. These costs began in July 2012 and will continue through 2023.

The Company reimbursed Alabama Power $11.9 million, $7.9 million, and $3.0 million in 2014, 2013, and 2012, respectively, for the revenue requirements. These costs have been approved for recovery by the Florida PSC through the Company's purchased power capacity cost recovery clause and by the FERC in the transmission facilities cost allocation tariff.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2014, 2013, or 2012.

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

Regulatory Assets and Liabilities

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

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

	2014	2013	Note
	(in thousands)		
Deferred income tax charges	$ 53,234	$ 47,573	(a)
Deferred income tax charges — Medicare subsidy	3,024	3,351	(b)
Asset retirement obligations	(5,087)	(6,089)	(a,j)
Other cost of removal obligations	(242,997)	(228,148)	(a)
Regulatory asset, offset to other cost of removal	8,410	—	(m)
Deferred income tax credits	(3,872)	(5,238)	(a)
Loss on reacquired debt	15,991	16,565	(c)
Vacation pay	10,006	9,521	(d,j)
Under recovered regulatory clause revenues	52,619	45,191	(e)
Property damage reserve	(35,111)	(35,380)	(f)
Fuel-hedging (realized and unrealized) losses	73,474	17,043	(g,j)
Fuel-hedging (realized and unrealized) gains	(112)	(6,962)	(g,j)
PPA charges	185,065	180,149	(j,k)
Other regulatory assets	9,753	12,772	(l)
Environmental remediation	48,271	50,384	(h,j)
Other regulatory liabilities	(649)	(8,804)	(f,j)
Retiree benefit plans, net	147,625	68,296	(i,j)
Total regulatory assets (liabilities), net	$ 319,644	$ 160,224	

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

(a) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(b) Recovered and amortized over periods not exceeding 14 years.

(c) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 40 years.

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

(e) Recorded and recovered or amortized as approved by the Florida PSC, generally within one year.

(f) Recorded and recovered or amortized as approved by the Florida PSC.

(g) Fuel-hedging assets and liabilities are recognized over the life of the underlying hedged purchase contracts, which generally do not exceed five years. Upon final settlement, actual costs incurred are recovered through the fuel cost recovery clause.

(h) Recovered through the environmental cost recovery clause when the remediation is performed.

(i) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 for additional information.

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

(k) Recovered over the life of the PPA for periods up to nine years.

(l) Comprised primarily of net book value of retired meters, deferred rate case expenses, and generation site evaluation costs. These costs are recorded and recovered or amortized as approved by the Florida PSC, generally over periods not exceeding eight years, or deferred pursuant to Florida statute while the Company continues to evaluate certain potential new generating projects.

(m) Recorded as authorized by the Florida PSC in a settlement agreement approved in December 2013. See Note 3 for additional information.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any

impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. The Company continuously monitors the over or under recovered fuel cost balance in light of the inherent variability in fuel costs. The Company is required to notify the Florida PSC if the projected fuel cost over or under recovery is expected to exceed 10% of the projected fuel revenue applicable for the period and indicate if an adjustment to the fuel cost recovery factor is being requested. The Company has similar retail cost recovery clauses for energy conservation costs, purchased power capacity costs, and environmental compliance costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. Annually, the Company petitions for recovery of projected costs including any true-up amounts from prior periods, and approved rates are implemented each January. See Note 3 under "Retail Regulatory Matters" for additional information.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC.

Income and Other Taxes

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

In accordance with accounting standards related to the uncertainty in income taxes, 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:

	2014	2013
	(in thousands)	
Generation	**$ 2,637,817**	$ 2,607,166
Transmission	**515,754**	473,378
Distribution	**1,156,872**	1,117,024
General	**182,734**	164,065
Plant acquisition adjustment	**1,776**	2,031
Total plant in service	**$ 4,494,953**	$ 4,363,664

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 3.6% in 2014, 2013, and 2012. 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 settlement agreement approved in December 2013 (Settlement Agreement), the Company is allowed to reduce depreciation expense and record a regulatory asset in an aggregate amount up to $62.5 million between January 2014 and June 2017. See Note 3 herein under "Retail Regulatory Matters – Retail Base Rate Case" for additional information.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) are computed as the present value of the 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. 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 the Company's combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, ash ponds, 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:

	2014	2013
	(in thousands)	
Balance at beginning of year	$ 16,184	$ 16,055
Liabilities incurred	—	518
Liabilities settled	(32)	(1,913)
Accretion	718	751
Cash flow revisions	(159)	773
Balance at end of year	$ 16,711	$ 16,184

The 2014 cash flow revisions are associated with asbestos and ash ponds at the Company's steam generation facilities. The 2013 cash flow revisions are associated with asbestos and an unloading dock at its generation facilities.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in landfills and surface impoundments at active generating power plants. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $62 million and ongoing post-closure care of approximately $11 million. The Company has previously recorded AROs associated with ash ponds of $6 million, or $11 million on a nominal dollar basis, based on existing state requirements. During 2015, the Company will record AROs for any incremental estimated closure costs resulting from acceleration in the timing of any currently planned closures and for differences between existing state

requirements and the requirements of the CCR Rule. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. The average annual AFUDC rate was 5.73% for 2014, 6.26% for 2013, and 6.72% for 2012. AFUDC, net of income taxes, as a percentage of net income after dividends on preference stock was 10.93%, 6.87%, and 5.36% for 2014, 2013, and 2012, 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 $48.0 million and $55.0 million. The Florida PSC also authorized the Company to make additional accruals above the $3.5 million at the Company's discretion. The Company accrued total expenses of $3.5 million in each of 2014, 2013, and 2012. As of December 31, 2014 and 2013, the balance in the Company's property damage reserve totaled approximately $35.7 million and $35.4 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. In December 2013, the Florida PSC approved the Settlement Agreement that, among other things, provides for recovery of costs associated with any tropical systems named by the National Hurricane Center through the initiation of a storm surcharge. The storm surcharge will begin, on an interim basis, 60 days following the filing of a cost recovery petition. The storm surcharge generally may not exceed $4.00/1,000 KWHs on monthly residential bills in aggregate for a calendar year. This limitation does not apply if the Company incurs in excess of $100 million in storm recovery costs that qualify for recovery in a given calendar year. This threshold amount is inclusive of the amount necessary to replenish the storm reserve to the level that existed as of December 31, 2013. See Note 3 herein under "Retail Regulatory Matters – Retail Base Rate Case" for additional details of the 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 $2.0 million and to defer expense recognition of liabilities greater than the balance in the reserve. The cost of settling claims is charged to the reserve. The injuries and damages reserve was $4.0 million and $3.6 million at December 31, 2014 and 2013, respectively. For 2014, $1.6 million and $2.4 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. For 2013, $1.6 million and $2.0 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. There were no liabilities in excess of the reserve balance at December 31, 2014 or 2013.

Cash and Cash Equivalents

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

Materials and Supplies

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

Fuel Inventory

Fuel inventory includes the average cost of oil, natural gas, coal, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC. Emissions allowances granted by the EPA are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (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. See Note 10 for additional information regarding derivatives.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2014.

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). In December 2014, the Company voluntarily contributed $30 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. 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, 2015, no other postretirement trust contributions are expected.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2011 for the 2012 plan year using discount rates for the pension plans and the other postretirement benefit plans of 4.98% and 4.88%, respectively, and an annual salary increase of 3.84%.

	2014	2013	2012
Discount rate:			
Pension plans	**4.18%**	5.02%	4.27%
Other postretirement benefit plans	**4.04**	4.86	4.06
Annual salary increase	**3.59**	3.59	3.59
Long-term return on plan assets:			
Pension plans	**8.20**	8.20	8.20
Other postretirement benefit plans	**8.08**	8.04	8.02

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

For purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $29.6 million and $2.6 million, respectively.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2014 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	9.00%	4.50%	2024
Post-65 medical	6.00	4.50	2024
Post-65 prescription	6.75	4.50	2024

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, 2014 as follows:

	1 Percent Increase	1 Percent Decrease
	(in thousands)	
Benefit obligation	$ 3,934	$ (3,334)
Service and interest costs	157	(133)

Pension Plans

The total accumulated benefit obligation for the pension plans was $438 million at December 31, 2014 and $353 million at December 31, 2013. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 395,328**	$ 413,501
Service cost	**10,181**	11,128
Interest cost	**19,433**	17,321
Benefits paid	**(15,635)**	(14,831)
Actuarial (gain) loss	**81,254**	(31,791)
Balance at end of year	**490,561**	395,328
Change in plan assets		
Fair value of plan assets at beginning of year	**385,639**	350,260
Actual return on plan assets	**33,512**	49,076
Employer contributions	**31,251**	1,134
Benefits paid	**(15,635)**	(14,831)
Fair value of plan assets at end of year	**434,767**	385,639
Accrued liability	**$ (55,794)**	$ (9,689)

At December 31, 2014, the projected benefit obligations for the qualified and non-qualified pension plans were $464 million and $26 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's pension plans consist of the following:

	2014	2013
	(in thousands)	
Prepaid pension costs	**$ —**	$ 11,533
Other regulatory assets, deferred	**145,815**	75,280
Current liabilities, other	**(1,307)**	(1,183)
Employee benefit obligations	**(54,487)**	(20,039)

Presented below are the amounts included in regulatory assets at December 31, 2014 and 2013 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 2015.

	2014	2013	Estimated Amortization in 2015
		(in thousands)	
Prior service cost	**$ 3,286**	$ 4,401	**$ 1,115**
Net (gain) loss	**142,529**	70,879	**9,281**
Regulatory assets	**$ 145,815**	$ 75,280	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in thousands)	
Regulatory assets:		
Beginning balance	**$ 75,280**	$ 139,261
Net (gain) loss	**76,209**	(54,432)
Reclassification adjustments:		
Amortization of prior service costs	**(1,115)**	(1,164)
Amortization of net gain (loss)	**(4,559)**	(8,385)
Total reclassification adjustments	**(5,674)**	(9,549)
Total change	**70,535**	(63,981)
Ending balance	**$ 145,815**	$ 75,280

Components of net periodic pension cost were as follows:

	2014	2013	2012
		(in thousands)	
Service cost	**$ 10,181**	$ 11,128	$ 9,101
Interest cost	**19,433**	17,321	17,199
Expected return on plan assets	**(28,468)**	(26,435)	(25,932)
Recognized net (gain) loss	**4,559**	8,385	3,913
Net amortization	**1,115**	1,164	1,262
Net periodic pension cost	**$ 6,820**	$ 11,563	$ 5,543

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, 2014, estimated benefit payments were as follows:

	Benefit Payments
	(in thousands)
2015	$ 22,002
2016	18,683
2017	19,950
2018	21,019
2019	22,229
2020 to 2024	129,877

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 68,579	$ 75,395
Service cost	1,163	1,355
Interest cost	3,235	2,982
Benefits paid	(4,061)	(3,583)
Actuarial (gain) loss	11,317	(7,900)
Plan amendment	(2,089)	—
Retiree drug subsidy	357	330
Balance at end of year	78,501	68,579
Change in plan assets		
Fair value of plan assets at beginning of year	17,474	16,227
Actual return on plan assets	1,578	2,119
Employer contributions	2,846	2,381
Benefits paid	(3,704)	(3,253)
Fair value of plan assets at end of year	18,194	17,474
Accrued liability	$ (60,307)	$ (51,105)

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's other postretirement benefit plans consist of the following:

	2014	2013
	(in thousands)	
Other regulatory assets, deferred	$ 6,100	$ —
Current liabilities, other	(639)	(687)
Other regulatory liabilities, deferred	(4,290)	(6,984)
Employee benefit obligations	(59,668)	(50,418)

Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2014 and 2013 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 2015.

	2014	2013	Estimated Amortization in 2015
		(in thousands)	
Prior service cost	$ (2,137)	$ 138	$ 25
Net (gain) loss	3,947	(7,122)	—
Net regulatory assets (liabilities)	$ 1,810	$ (6,984)	

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in thousands)	
Net regulatory assets (liabilities):		
Beginning balance	**$ (6,984)**	$ 2,169
Net (gain) loss	**11,045**	(8,967)
Change in prior service costs	**(2,089)**	—
Reclassification adjustments:		
Amortization of prior service costs	**(186)**	(186)
Amortization of net gain (loss)	**24**	—
Total reclassification adjustments	**(162)**	(186)
Total change	**8,794**	(9,153)
Ending balance	**$ 1,810**	$ (6,984)

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

	2014	2013	2012
		(in thousands)	
Service cost	**$ 1,163**	$ 1,355	$ 1,167
Interest cost	**3,235**	2,982	3,367
Expected return on plan assets	**(1,306)**	(1,238)	(1,311)
Net amortization	**162**	186	379
Net periodic postretirement benefit cost	**$ 3,254**	$ 3,285	$ 3,602

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 thousands)	
2015	$ 4,694	$ (431)	$ 4,263
2016	4,982	(480)	4,502
2017	5,136	(535)	4,601
2018	5,300	(594)	4,706
2019	5,326	(660)	4,666
2020 to 2024	27,399	(3,430)	23,969

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, 2014 and 2013, along with the targeted mix of assets for each plan, is presented below:

	Target	2014	2013
Pension plan assets:			
Domestic equity	26%	**30%**	31%
International equity	25	**23**	25
Fixed income	23	**27**	23
Special situations	3	**1**	1
Real estate investments	14	**14**	14
Private equity	9	**5**	6
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	25%	**29%**	30%
International equity	24	**22**	24
Domestic fixed income	25	**29**	25
Special situations	3	**1**	1
Real estate investments	14	**14**	14
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, 2014 and 2013. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management

relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

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

- ***Domestic and international equity.*** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- ***Fixed income.*** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- ***Real estate investments and private equity.*** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

The fair values of pension plan assets as of December 31, 2014 and 2013 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2014:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Domestic equity*	$ 76,460	$ 31,588	$ —	$ 108,048
International equity*	47,988	44,223	—	92,211
Fixed income:				
U.S. Treasury, government, and agency bonds	—	31,372	—	31,372
Mortgage- and asset-backed securities	—	8,438	—	8,438
Corporate bonds	—	50,931	—	50,931
Pooled funds	—	23,063	—	23,063
Cash equivalents and other	130	29,597	—	29,727
Real estate investments	13,154	—	50,281	63,435
Private equity	—	—	25,573	25,573
Total	$ 137,732	$ 219,212	$ 75,854	$ 432,798
Liabilities:				
Derivatives	$ (87)	$ —	$ —	$ (87)
Total	$ 137,645	$ 219,212	$ 75,854	$ 432,711

* 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, 2013:	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)	Total
		(in thousands)		
Assets:				
Domestic equity*	$ 63,269	$ 37,037	$ —	$ 100,306
International equity*	48,606	44,941	—	93,547
Fixed income:				
U.S. Treasury, government, and agency bonds	—	26,461	—	26,461
Mortgage- and asset-backed securities	—	6,873	—	6,873
Corporate bonds	—	43,222	—	43,222
Pooled funds	—	20,810	—	20,810
Cash equivalents and other	38	9,851	—	9,889
Real estate investments	11,493	—	44,139	55,632
Private equity	—	—	25,201	25,201
Total	$ 123,406	$ 189,195	$ 69,340	$ 381,941
Liabilities:				
Derivatives	$ —	$ (115)	$ —	$ (115)
Total	$ 123,406	$ 189,080	$ 69,340	$ 381,826

* 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.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2014 and 2013 were as follows:

	2014		2013	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in thousands)		
Beginning balance	$ 44,139	$ 25,201	$ 37,039	$ 26,129
Actual return on investments:				
Related to investments held at year end	4,263	2,697	3,357	376
Related to investments sold during the year	1,488	(727)	1,310	2,282
Total return on investments	5,751	1,970	4,667	2,658
Purchases, sales, and settlements	391	(1,598)	2,433	(3,586)
Ending balance	$ 50,281	$ 25,573	$ 44,139	$ 25,201

The fair values of other postretirement benefit plan assets as of December 31, 2014 and 2013 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Domestic equity*	$ 3,105	$ 1,283	$ —	$ 4,388
International equity*	1,949	1,798	—	3,747
Fixed income:				
U.S. Treasury, government, and agency bonds	—	1,274	—	1,274
Mortgage- and asset-backed securities	—	342	—	342
Corporate bonds	—	2,071	—	2,071
Pooled funds	—	937	—	937
Cash equivalents and other	510	1,203	—	1,713
Real estate investments	534	—	2,042	2,576
Private equity	—	—	1,039	1,039
Total	$ 6,098	$ 8,908	$ 3,081	$ 18,087
Liabilities:				
Derivatives	$ (4)	$ —	$ —	$ (4)
Total	$ 6,094	$ 8,908	$ 3,081	$ 18,083

* 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, 2013:	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)	Total
		(in thousands)		
Assets:				
Domestic equity*	$ 2,778	$ 1,628	$ —	$ 4,406
International equity*	2,136	1,973	—	4,109
Fixed income:				
U.S. Treasury, government, and agency bonds	—	1,161	—	1,161
Mortgage- and asset-backed securities	—	303	—	303
Corporate bonds	—	1,897	—	1,897
Pooled funds	—	1,417	—	1,417
Cash equivalents and other	1	433	—	434
Real estate investments	504	—	1,939	2,443
Private equity	—	—	1,108	1,108
Total	$ 5,419	$ 8,812	$ 3,047	$ 17,278
Liabilities:				
Derivatives	$ —	$ (5)	$ —	$ (5)
Total	$ 5,419	$ 8,807	$ 3,047	$ 17,273

* 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.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2014 and 2013 were as follows:

	2014		2013	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in thousands)		
Beginning balance	**$ 1,939**	**$ 1,108**	$ 1,667	$ 1,155
Actual return on investments:				
Related to investments held at year end	**27**	**26**	108	16
Related to investments sold during the year	**60**	**(30)**	57	104
Total return on investments	**87**	**(4)**	165	120
Purchases, sales, and settlements	**16**	**(65)**	107	(167)
Ending balance	**$ 2,042**	**$ 1,039**	$ 1,939	$ 1,108

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 2014, 2013, and 2012 were $4.2 million, $4.1 million, and $4.0 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 o

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

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against Georgia Power alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by the Company. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. These actions were filed concurrently with the issuance of notices of violation of the NSR provisions to the Company with respect to the Company's Plant Crist. The case against Georgia Power (including claims related to a unit co-owned by the Company) has been administratively closed in the U.S. District Court for the Northern District of Georgia since 2001.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

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 properties. 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, 2014, the Company's environmental remediation liability included estimated costs of environmental remediation projects of approximately $48.3 million. For 2014, approximately $4.5 million was included in under recovered regulatory clause revenues and other current liabilities, and approximately $43.7 million was included in other regulatory assets, deferred and other deferred credits and liabilities. These estimated costs relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at the Company's substations. The schedule for completion of the remediation projects is subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through the Company's environmental cost recovery clause; therefore, these liabilities have no impact on net income.

The final outcome of these matters cannot be determined at this time. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, the Company does not believe that additional liabilities, if any, at these sites would be material to the Company's financial statements.

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates.

Retail Base Rate Case

In December 2013, the Florida PSC voted to approve the Settlement Agreement among the Company and all of the intervenors to the docketed proceeding with respect to the Company's request to increase retail base rates. Under the terms of the Settlement Agreement, the Company (1) increased base rates designed to produce an additional $35 million in annual revenues effective January 2014 and subsequently increased base rates designed to produce an additional $20 million in annual revenues effective January 2015; (2)

continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); and (3) will accrue a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until the next base rate adjustment date or January 1, 2017, whichever comes first.

The Settlement Agreement also includes a self-executing adjustment mechanism that will increase the authorized ROE midpoint and range by 25 basis points in the event the 30-year treasury yield rate increases by an average of at least 75 basis points above 3.7947% for a consecutive six-month period.

The Settlement Agreement also provides that the Company may reduce depreciation expense and record a regulatory asset that will b included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017. In any given month, such depreciation expense reduction may not exceed the amount necessary for the ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized ROE range then in effect. Recovery of the regulatory asset will occur over a period to be determined by the Florida PSC in the Company's next base rate case or next depreciation and dismantlement study proceeding, whichever comes first. As a result, the Company recognized an $8.4 million reduction in depreciation expense in 2014.

Pursuant to the Settlement Agreement, the Company may not request an increase in its retail base rates to be effective until after June 2017, unless the Company's actual retail ROE falls below the authorized ROE range.

Cost Recovery Clauses

On October 22, 2014, the Florida PSC approved the Company's annual rate clause request for its fuel, purchased power capacity, environmental, and energy conservation cost recovery factors for 2015. The net effect of the approved changes is an expected $41.2 million increase in annual revenue for 2015. The increased revenues will not have a significant impact on net income since most of th revenues will be offset by expenses.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment.

Retail Fuel Cost Recovery

The Company has established fuel cost recovery rates as approved by the Florida PSC. If, at any time during the year, the projected year-end fuel cost over or under recovery balance exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested. The Company filed such notice with the Florida PSC on July 18, 2014, but no adjustment to the factor was requested for 2014.

At December 31, 2014 and 2013, the under recovered fuel balance was approximately $39.9 million and $21.0 million, respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

Purchased Power Capacity Recovery

The Company has established purchased power capacity recovery cost rates as approved by the Florida PSC. If the projected year-end purchased power capacity cost over or under recovery balance exceeds 10% of the projected purchased power capacity revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the purchased power capacity cost recovery factor is being requested.

At December 31, 2014 and 2013, the under recovered purchased power capacity balance was approximately $0.3 million and $2.8 million, respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

Environmental Cost Recovery

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operations and maintenance expenses, emissions allowance expense, depreciation, and a return on net average investment. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the FDEP for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA.

In 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality. The Company's environmental compliance plan as filed in 2007 contemplated implementation of specific projects identified in the plan

from 2007 through 2018. The Florida PSC's approval of the stipulation also required the Company to file annual updates to the plan and outlined a process for approval of additional elements in the plan when they became committed projects. In the 2010 update filing, the Company identified several elements of the updated plan that the Company had decided to implement. Following the process outlined in the original approved stipulation, these additional projects were approved by the Florida PSC later in 2010. The Florida PSC acknowledged that the costs of the approved projects associated with the Company's Clean Air Interstate Rule and Clean Air Visibility Rule compliance plans are eligible for recovery through the environmental cost recovery clause.

Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2014 and 2013, the under recovered environmental balance was approximately $9.8 million and $14.4 million, respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

In 2012, the Mississippi PSC approved Mississippi Power's request for a certificate of public convenience and necessity to construct a scrubber on Plant Daniel Units 1 and 2. These units are jointly owned by Mississippi Power and the Company, with 50% ownership each. The estimated total cost of the project is approximately $660 million, with the Company's portion being $330 million, excluding AFUDC, and it is scheduled for completion in December 2015. The Company's portion of the cost is expected to be recovered through the environmental cost recovery clause. On August 28, 2014, the Chancery Court of Harrison County, Mississippi dismissed an appeal by the Sierra Club related to the construction of the scrubber on Plant Daniel Units 1 and 2.

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, 2014 and 2013, the under recovered energy conservation balance was approximately $2.6 million and $7.0 million, respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Mississippi Power jointly own Plant Daniel Units 1 and 2, which together represent capacity of 1,000 MWs. Plant Daniel is a generating plant located in Jackson County, Mississippi. In accordance with the operating agreement, Mississippi Power acts as the Company's agent with respect to the construction, operation, and maintenance of these units.

The Company and Georgia Power jointly own the 818 MWs capacity Plant Scherer Unit 3. Plant Scherer is a generating plant located near Forsyth, Georgia. In accordance with the operating agreement, Georgia Power acts as the Company's agent with respect to the construction, operation, and maintenance of the unit.

At December 31, 2014, 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 thousands)	
Plant in service	$ 387,511 [(a)]	$ 285,834
Accumulated depreciation	130,069	177,304
Construction work in progress	2,912	286,343
Company Ownership	25%	50%

(a) Includes net plant acquisition adjustment of $1.8 million.

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 combined state income tax returns for the States of Alabama, Georgia, and Mississippi. In addition, the Company files a separate company income tax return for the State of Florida. 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:

	2014	2013	2012
		(in thousands)	
Federal -			
Current	$ 22,771	$ 5,009	$ (92,610)
Deferred	52,602	63,134	161,096
	75,373	68,143	68,486
State -			
Current	(39)	(2,410)	(2,484)
Deferred	12,728	13,935	13,209
	12,689	11,525	10,725
Total	$ 88,062	$ 79,668	$ 79,211

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:

	2014	2013
	(in thousands)	
Deferred tax liabilities-		
Accelerated depreciation	$ 776,953	$ 721,087
Property basis differences	52,242	45,960
Fuel recovery clause	16,148	7,972
Pension and other employee benefits	34,405	25,800
Regulatory assets associated with employee benefit obligations	59,788	27,660
Regulatory assets associated with asset retirement obligations	6,768	6,554
Other	21,712	23,947
Total	968,016	858,980
Deferred tax assets-		
Federal effect of state deferred taxes	30,587	24,277
Postretirement benefits	18,033	17,816
Pension and other employee benefits	65,506	33,015
Property reserve	13,440	15,144
Asset retirement obligations	6,768	6,554
Alternative minimum tax carryforward	18,200	18,420
Other	18,893	17,780
Total	171,427	133,006
Net deferred tax liabilities	796,589	725,974
Portion included in current assets/(liabilities), net	3,134	8,381
Accumulated deferred income taxes	$ 799,723	$ 734,355

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

At December 31, 2014, tax-related regulatory assets to be recovered from customers were $56.3 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, 2014, the tax-related regulatory liabilities to be credited to customers were $3.9 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 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 $1.3 million in 2014 and $1.4 million in both 2013 and 2012. At December 31, 2014, 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:

	2014	2013	2012
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**3.5**	3.5	3.3
Non-deductible book depreciation	**0.4**	0.5	0.5
Differences in prior years' deferred and current tax rates	**(0.1)**	(0.2)	(0.2)
AFUDC equity	**(1.8)**	(1.1)	(0.9)
Other, net	**0.1**	(0.1)	(0.2)
Effective income tax rate	**37.1%**	37.6%	37.5%

The decrease in the Company's 2014 effective tax rate is primarily the result of an increase in AFUDC equity which is not taxable.

Unrecognized Tax Benefits

Changes during the year in unrecognized tax benefits were as follows:

	2014	2013	2012
		(in thousands)	
Unrecognized tax benefits at beginning of year	$ **45**	$ 5,007	$ 2,892
Tax positions increase from current periods	**46**	45	2,630
Tax positions increase/(decrease) from prior periods	**(45)**	(5,007)	515
Reductions due to settlements	**—**	—	(1,030)
Balance at end of year	$ **46**	$ 45	$ 5,007

The tax positions increase from current periods and decrease from prior periods for 2014 relate primarily to the research and development credit. The tax positions decrease from prior periods for 2013 relate primarily to the tax accounting method change for repairs related to generation assets. See "Tax Method of Accounting for Repairs" herein for additional information.

The impact on the Company's effective tax rate, if recognized, is as follows:

	2014	2013	2012
		(in thousands)	
Tax positions impacting the effective tax rate	$ **46**	$ 45	$ 45
Tax positions not impacting the effective tax rate	**—**	—	4,962
Balance of unrecognized tax benefits	$ **46**	$ 45	$ 5,007

The tax positions impacting the effective tax rate for all periods presented relate primarily to the research and development credit. The tax positions not impacting the effective tax rate for 2012 relate to the tax accounting method change for repairs related to generation assets. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

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 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 federal income tax return and has received a partial acceptance letter from the IRS; however, the IRS has not finalized its audit. 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 2010.

Tax Method of Accounting for Repairs

In 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. Additionally, in April 2013, the IRS issued Revenue Procedure 2013-24, which provides guidance for taxpayers related to the deductibility of repair costs associated with generation assets. Based on a review of the regulations, Southern Company incorporated provisions related to repair costs for generation assets into its consolidated 2012 federal income tax return and reversed all related unrecognized tax positions. In September 2013, the IRS issued Treasury Decision 9636, "Guidance Regarding Deduction and Capitalization of Expenditures Related to Tangible Property," which are final tangible property regulations applicable to taxable years beginning on or after January 1, 2014. Southern Company continues to review this guidance; however, these regulations are not expected to have a material impact on the Company's financial statements.

6. FINANCING

Securities Due Within One Year

At December 31, 2014, the Company had no scheduled maturities of long-term debt due within one year.

Maturities from 2016 through 2019 applicable to total long-term debt are as follows: $110 million in 2016 and $85 million in 2017. There are no scheduled maturities in 2015, 2018, or 2019.

Senior Notes

At each of December 31, 2014 and 2013, the Company had a total of $1.07 billion and $945 million of senior notes outstanding, respectively. These senior notes are effectively subordinate to all secured debt of the Company, which totaled approximately $41 million at December 31, 2014.

In September 2014, the Company issued $200 million aggregate principal amount of Series 2014A 4.55% Senior Notes due October 1, 2044. The proceeds were used to repay a portion of the Company's outstanding short-term indebtedness, for general corporate purposes, including the Company's continuous construction program and for repayment at maturity $75 million aggregate principal amount of the Company's Series K 4.90% Senior Notes due October 1, 2014.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2014 and 2013 was $309 million and $296 million, respectively.

In April 2014, the Company executed a loan agreement with Mississippi Business Finance Corporation (MBFC) related to MBFC's issuance of $29.075 million aggregate principal amount of Pollution Control Revenue Refunding Bonds, First Series 2014 (Gulf Power Company Project) due April 1, 2044 for the benefit of the Company. The proceeds were used to redeem $29.075 million aggregate principal amount of MBFC Pollution Control Revenue Refunding Bonds, Series 2003 (Gulf Power Company Project).

In June 2014, the Company reoffered to the public $13 million aggregate principal amount of MBFC Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2012 (Gulf Power Company Project), which had been previously purchased and held by the Company since December 2013.

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, 2014. 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 2014, the Company issued 500,000 shares of common stock to Southern Company and realized proceeds of $50 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, 2014, the Company issued 200,000 shares of common stock to Southern Company and realized proceeds of $20 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

Dividend Restrictions

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

Assets Subject to Lien

The Company has granted a lien on its property at Plant Daniel in connection with the issuance of two series of pollution control revenue bonds with an outstanding principal amount of $41 million. 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, 2014, committed credit arrangements with banks were as follows:

Expires					Executable Term-Loans		Due Within One Year	
2015	2016	2017	Total	Unused	One Year	Two Years	Term Out	No Term Out
			(in millions)					
$ 80	$ 165	$ 30	$ 275	$ 275	$ 50	$ —	$ 50	$ 30

Subject to applicable market conditions, the Company expects to renew its bank credit arrangements as needed, prior to expiration. Most of the $275 million of unused credit arrangements with banks provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper program. The Company had $69 million of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014. In addition, at December 31, 2014, the Company had $78 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months. 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.

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, 2014, the Company was in compliance with these covenants.

For short-term cash needs, the Company borrows primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements described above. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank loans are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Commercial Paper at the End of the Period	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2014	**$ 110**	**0.3%**
December 31, 2013	$ 136	0.2%

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 2014, 2013, and 2012, the Company incurred fuel expense of $604.6 million, $532.8 million, and $544.9 million, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

In addition, the Company has entered into various long-term commitments for the purchase of capacity, energy, and transmission, some of which are accounted for as operating leases. The energy-related costs associated with PPAs are recovered through the fuel cost recovery clause. The capacity and transmission-related costs associated with PPAs are recovered through the purchased power capacity cost recovery clause. Capacity expense under purchased power agreements accounted for as operating leases was $49.5 million, $21.3 million, and $24.6 million for 2014, 2013, and 2012, respectively.

Estimated total minimum long-term commitments at December 31, 2014 were as follows:

	Operating Lease PPAs
	(in millions)
2015	$ 78.7
2016	78.7
2017	78.8
2018	78.9
2019	78.9
2020 and thereafter	270.3
Total	$ 664.3

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

Operating Leases

In addition to the operating lease PPAs discussed above, the Company has other operating lease agreements with various terms and expiration dates. Total rent expense was $15.0 million, $18.0 million, and $20.1 million for 2014, 2013, and 2012, respectively.

Estimated total minimum lease payments under these operating leases at December 31, 2014 were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
		(in millions)	
2015	$ 15.1	$ 0.1	$ 15.2
2016	15.0	0.1	15.1
2017	1.4	0.1	1.5
Total	$ 31.5	$ 0.3	$ 31.8

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 each lease term. The Company and Mississippi Power also have separate lease agreements for other railcars that do not include purchase options. The Company's share of the lease costs, charged to fuel inventory and recovered through the retail fuel cost recovery clause, was $2.8 million in 2014, $3.1 million in 2013, and $3.6 million in 2012. The Company's annual railcar lease payments for 2015 through 2017 will average approximately $1.6 million. The Company has no lease payment obligations for the period 2018 and thereafter.

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2014, there were 195 current and former employees of the Company participating in the stock option program. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. Stock options held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted stock options for 432,371 shares, 285,209 shares, and 244,607 shares, respectively. The weighted average grant-date fair value of stock options granted during 2014, 2013, and 2012, derived using the Black-Scholes stock option pricing model, was $2.20, $2.93, and $3.39, respectively.

The compensation cost and tax benefits related to the grant of Southern Company stock options to the Company's employees and the exercise of stock options are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. No cash proceeds are received by the Company upon the exercise of stock options. The amounts were not material for any year presented.

As of December 31, 2014, 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, 2014, 2013, and 2012 was $5.2 million, $1.7 million, and $3.8 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $2.0 million, $0.6 million, and $1.5 million for the years ended December 31, 2014, 2013, and 2012, respectively. As of December 31, 2014, the aggregate intrinsic value for the options outstanding and options exercisable was $11.9 million and $7.7 million, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on

Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount. Performance share units held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted performance share units of 37,829, 30,627, and 29,444, respectively. The weighted average grant-date fair value of performance share units granted during 2014, 2013, and 2012, 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 $37.54, $40.50, and $41.99, respectively.

The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. For the years ended December 31, 2014, 2013, and 2012, total compensation cost for performance share units recognized in income was approximately $1.0 million annually, with the related tax benefit also recognized in income of $0.4 million annually. The compensation cost and tax benefits related to the grant of Southern Company performance share units to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2014, there was $1.3 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 20 months.

9. FAIR VALUE MEASUREMENTS

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

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

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

As of December 31, 2014, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Energy-related derivatives	$ —	$ 125	$ —	$ 125
Cash equivalents	18,032	—	—	18,032
Total	$ 18,032	$ 125	$ —	$ 18,157
Liabilities:				
Energy-related derivatives	$ —	$ 72,435	$ —	$ 72,435

As of December 31, 2013, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2013:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Energy-related derivatives	$ —	$ 6,962	$ —	$ 6,962
Cash equivalents	15,929	—	—	15,929
Total	$ 15,929	$ 6,962	$ —	$ 22,891
Liabilities:				
Energy-related derivatives	$ —	$ 17,043	$ —	$ 17,043

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. See Note 10 for additional information on how these derivatives are used.

As of December 31, 2014 and 2013, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2014:	*(in thousands)*			
Cash equivalents:				
Money market funds	$18,032	None	Daily	Not applicable
As of December 31, 2013:				
Cash equivalents:				
Money market funds	$15,929	None	Daily	Not applicable

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2014 and 2013, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
2014	**$ 1,369,594**	**$ 1,476,954**
2013	$ 1,233,163	$ 1,261,889

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 may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. See Note 9 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Florida PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in electricity prices, the Company may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

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

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

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

At December 31, 2014, the net volume of energy-related derivative contracts for natural gas positions totaled 84.59 million mmBtu for the Company, with the longest hedge date of 2019 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, 2014, 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, 2015 are not material. The Company has deferred gains and losses that are expected to be amortized into earnings through 2020.

Derivative Financial Statement Presentation and Amounts

At December 31, 2014 and 2013, the fair value of energy-related derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in thousands)			*(in thousands)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:						
	Other current assets	**$ 34**	$4,893	Liabilities from risk management activities	**$36,922**	$ 6,470
	Other deferred charges and assets	**78**	2,069	Other deferred credits and liabilities	**35,502**	10,573
Total derivatives designated as hedging instruments for regulatory purposes		**$ 112**	$6,962		**$72,424**	$17,043

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2014 and 2013.

The derivative contracts of the Company are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related derivative contracts contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts at December 31, 2014 and 2013 are presented in the following tables.

	Fair Value				
Assets	**2014**	2013	**Liabilities**	**2014**	2013
	(in thousands)			*(in thousands)*	
Energy-related derivatives presented in the Balance Sheet [a]	**$ 125**	$6,962	Energy-related derivatives presented in the Balance Sheet [a]	**$72,435**	$17,043
Gross amounts not offset in the Balance Sheet [b]	**(123)**	(5,775)	Gross amounts not offset in the Balance Sheet [b]	**(123)**	(5,775)
Net energy-related derivative assets	**$ 2**	$1,187	**Net energy-related derivative liabilities**	**$72,312**	$11,268

(a) The Company does not offset fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.
(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

At December 31, 2014 and 2013, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in thousands)			*(in thousands)*	
Energy-related derivatives:	Other regulatory assets, current	**$(36,922)**	$ (6,470)	Other regulatory liabilities, current	**$ 34**	$4,893
	Other regulatory assets, deferred	**(35,502)**	(10,573)	Other regulatory liabilities, deferred	**78**	2,069
Total energy-related derivative gains (losses)		**$(72,424)**	$(17,043)		**$ 112**	$6,962

For the years ended December 31, 2014, 2013, and 2012, 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	2014	2013	2012	Statements of Income Location	2014	2013	2012
		(in thousands)				*(in thousands)*	
Interest rate derivatives	$—	$—	$—	Interest expense, net of amounts capitalized	$(606)	$(769)	$(933)

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2014, 2013, and 2012, 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, 2014, the Company's collateral posted with its derivative counterparties was not material.

At December 31, 2014, the fair value of derivative liabilities with contingent features was $20.5 million. However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $54.5 million and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

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

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

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2014 and 2013 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preference Stock
		(in thousands)	
March 2014	**$ 407,132**	**$ 73,888**	**$ 36,743**
June 2014	**383,531**	**68,877**	**34,097**
September 2014	**438,334**	**88,600**	**46,547**
December 2014	**361,485**	**49,850**	**22,789**
March 2013	$ 326,274	$ 51,640	$ 21,792
June 2013	371,173	69,151	32,582
September 2013	399,361	87,776	44,754
December 2013	343,493	56,436	25,301

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

SELECTED FINANCIAL AND OPERATING DATA 2010-2014
Gulf Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in thousands)	**$ 1,590,482**	$ 1,440,301	$ 1,439,762	$ 1,519,812	$ 1,590,209
Net Income After Dividends on Preference Stock (in thousands)	**$ 140,176**	$ 124,429	$ 125,932	$ 105,005	$ 121,511
Cash Dividends on Common Stock (in thousands)	**$ 123,200**	$ 115,400	$ 115,800	$ 110,000	$ 104,300
Return on Average Common Equity (percent)	**11.02**	10.30	10.92	9.55	11.69
Total Assets (in thousands)	**$ 4,708,259**	$ 4,337,571	$ 4,177,402	$ 3,871,881	$ 3,584,939
Gross Property Additions (in thousands)	**$ 360,937**	$ 304,778	$ 325,237	$ 337,830	$ 285,379
Capitalization (in thousands):					
Common stock equity	**$ 1,309,590**	$ 1,235,126	$ 1,180,742	$ 1,124,948	$ 1,075,036
Preference stock	**146,504**	146,504	97,998	97,998	97,998
Long-term debt	**1,369,594**	1,158,163	1,185,870	1,235,447	1,114,398
Total (excluding amounts due within one year)	**$ 2,825,688**	$ 2,539,793	$ 2,464,610	$ 2,458,393	$ 2,287,432
Capitalization Ratios (percent):					
Common stock equity	**46.3**	48.6	47.9	45.8	47.0
Preference stock	**5.2**	5.8	4.0	4.0	4.3
Long-term debt	**48.5**	45.6	48.1	50.2	48.7
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**388,292**	383,980	379,922	378,248	376,561
Commercial	**54,892**	54,567	53,808	53,450	53,263
Industrial	**260**	260	264	273	272
Other	**603**	582	577	565	562
Total	**444,047**	439,389	434,571	432,536	430,658
Employees (year-end)	**1,384**	1,410	1,416	1,424	1,330

SELECTED FINANCIAL AND OPERATING DATA 2010-2014 (continued)
Gulf Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in thousands):					
Residential	$ 700,442	$ 632,495	$ 609,454	$ 637,352	$ 707,196
Commercial	408,401	395,062	389,936	408,389	439,468
Industrial	153,167	138,585	140,490	158,367	157,591
Other	4,530	3,858	4,591	4,382	4,471
Total retail	1,266,540	1,170,000	1,144,471	1,208,490	1,308,726
Wholesale — non-affiliates	129,151	109,386	106,881	133,555	109,172
Wholesale — affiliates	130,107	99,577	123,636	111,346	110,051
Total revenues from sales of electricity	1,525,798	1,378,963	1,374,988	1,453,391	1,527,949
Other revenues	64,684	61,338	64,774	66,421	62,260
Total	$ 1,590,482	$ 1,440,301	$ 1,439,762	$ 1,519,812	$ 1,590,209
Kilowatt-Hour Sales (in thousands):					
Residential	5,362,423	5,088,828	5,053,724	5,304,769	5,651,274
Commercial	3,838,148	3,809,939	3,858,521	3,911,399	3,996,502
Industrial	1,849,255	1,700,174	1,725,121	1,798,688	1,685,817
Other	25,236	20,946	25,267	25,430	25,602
Total retail	11,075,062	10,619,887	10,662,633	11,040,286	11,359,195
Wholesale — non-affiliates	1,670,121	1,162,308	977,395	2,012,986	1,675,079
Wholesale — affiliates	3,283,685	3,127,350	4,369,964	2,607,873	2,436,883
Total	16,028,868	14,909,545	16,009,992	15,661,145	15,471,157
Average Revenue Per Kilowatt-Hour (cents):					
Residential	13.06	12.43	12.06	12.01	12.51
Commercial	10.64	10.37	10.11	10.44	11.00
Industrial	8.28	8.15	8.14	8.80	9.35
Total retail	11.44	11.02	10.73	10.95	11.52
Wholesale	5.23	4.87	4.31	5.30	5.33
Total sales	9.52	9.25	8.59	9.28	9.88
Residential Average Annual Kilowatt-Hour Use Per Customer	13,865	13,301	13,303	14,028	15,036
Residential Average Annual Revenue Per Customer	$ 1,811	$ 1,653	$ 1,604	$ 1,685	$ 1,882
Plant Nameplate Capacity Ratings (year-end) (megawatts)	2,663	2,663	2,663	2,663	2,663
Maximum Peak-Hour Demand (megawatts):					
Winter	2,684	1,729	2,130	2,485	2,544
Summer	2,424	2,356	2,344	2,527	2,519
Annual Load Factor (percent)	51.1	55.9	56.3	54.5	56.1
Plant Availability Fossil-Steam (percent)*	89.4	92.8	82.5	84.7	94.7
Source of Energy Supply (percent):					
Coal	44.5	36.4	34.6	49.4	64.6
Gas	22.2	23.0	23.5	24.0	17.8
Purchased power —					
From non-affiliates	28.9	37.0	40.2	22.3	13.2
From affiliates	4.4	3.6	1.7	4.3	4.4
Total	100.0	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

[This page intentionally left blank]

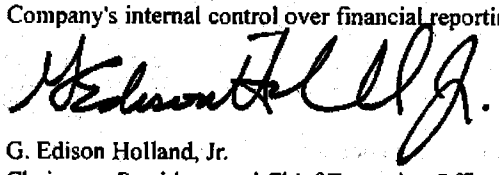
MISSISSIPPI POWER COMPANY

FINANCIAL SECTION

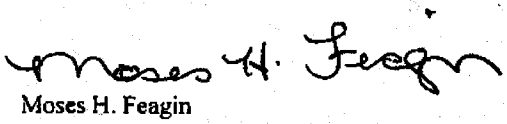
MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Mississippi Power Company 2014 Annual Report

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, 2014.



G. Edison Holland, Jr.
Chairman, President, and Chief Executive Officer



Moses H. Feagin
Vice President, Chief Financial Officer, and Treasurer

March 2, 2015

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, 2014 and 2013, 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, 2014. 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-387 to II-435) present fairly, in all material respects, the financial position of Mississippi Power Company as of December 31, 2014 and 2013, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
March 2, 2015

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
APA	Asset purchase agreement
ASC	Accounting Standards Codification
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
FERC	Federal Energy Regulatory Commission
GAAP	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 account for use in mitigating future rate impacts for customers
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 operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
ROE	Return on equity
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
scrubber	Flue gas desulfurization system

DEFINITIONS
(continued)

Term	Meaning
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
SMEPA	South Mississippi Electric Power Association
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
Southern Company system	The Southern Company, the traditional operating companies, Southern Power, Southern Electric Generating Company, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SRR	System Restoration Rider
traditional operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power Company

OVERVIEW

Business Activities

Mississippi Power Company (the Company) operates as a vertically integrated utility providing electricity 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 selling electricity. These factors include the Company's ability to maintain and grow energy sales and to maintain a constructive regulatory environment that provides timely recovery of prudently-incurred costs. These costs include those related to the completion and operation of major construction projects, primarily the Kemper IGCC and the Plant Daniel scrubber project, projected long-term demand growth, reliability, fuel, and increasingly stringent environmental standards, as well as ongoing capital expenditures required for maintenance. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

The Company's retail base rates are set under the PEP, a rate plan approved by the Mississippi PSC. PEP was designed with the objective to reduce the impact of rate changes on customers and provide incentives for the Company to keep customer prices low and customer satisfaction and reliability high.

In 2010, the Mississippi PSC issued a CPCN authorizing the acquisition, construction, and operation of the Kemper IGCC. The certificated cost estimate of the Kemper IGCC established by the Mississippi PSC was $2.4 billion with a construction cost cap of $2.88 billion, net of $245.3 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (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 Company's current cost estimate for the Kemper IGCC in total is approximately $6.20 billion, which includes approximately $4.93 billion of costs subject to the construction cost cap. The Company does not intend to seek any rate recovery or joint owner contributions for any related costs that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. The Company has recorded pre-tax charges to income for revisions to the cost estimate of $868.0 million ($536.0 million after tax), $1.10 billion ($680.5 million after tax), and $78.0 million ($48.2 million after tax) in 2014, 2013 and 2012, respectively.

The Company placed the combined cycle and the associated common facilities portion of the Kemper IGCC project in service on August 9, 2014 and continues to focus on completing the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities. The in-service date for the remainder of the Kemper IGCC is currently expected to occur in the first half of 2016. The current cost estimate includes costs through March 31, 2016. As a result of the additional factors that have the potential to impact start-up and operational readiness activities for this first-of-a-kind technology as described herein, the risk of further schedule extensions and/or cost increases, which could be material, remains. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information, including the discussion of risks related to the Kemper IGCC.

On February 12, 2015, the Mississippi Supreme Court (Court) issued its decision in a legal challenge filed by Thomas A. Blanton with respect to the Mississippi PSC's March 2013 order that authorized the collection of $156 million annually (2013 MPSC Rate Order) to be recorded as Mirror CWIP. The Court reversed the 2013 MPSC Rate Order, deemed the 2013 Settlement Agreement (defined below) between the Company and the Mississippi PSC unenforceable due to a lack of public notice for the related proceedings, and directed the Mississippi PSC to enter an order requiring the Company to refund the Mirror CWIP amounts collected pursuant to the 2013 MPSC Rate Order. As of December 31, 2014, $257.2 million had been collected by the Company. The Company continues to analyze the Court's opinion and expects to file a motion for rehearing. See "2015 Mississippi Supreme Court Decision" herein for additional information.

Key Performance Indicators

The Company continues to focus on several key performance indicators, including the construction and start-up of the Kemper IGCC, to measure the Company's performance for customers and employees.

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, which the Company achieved during 2014.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The Company's 2014 fossil Peak Season EFOR of 0.55% was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The Company's 2014 performance was better than the target for these transmission and distribution reliability measures.

The Company uses net income (loss) after dividends on preferred stock as the primary measure of the Company's financial performance. The Company's results were below target for 2014 due to the increased cost estimate for the Kemper IGCC above the $2.88 billion cost cap and the 2015 Court decision. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Performance Evaluation Plan" and FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" herein for additional information. See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance.

Earnings

The Company's net income (loss) after dividends on preferred stock was ($328.7) million in 2014 compared to ($476.6) million in 2013. The decreased net loss in 2014 was primarily the result of lower pre-tax charges of $868.0 million ($536.0 million after tax) in 2014 compared to pre-tax charges of $1.1 billion ($680.5 million after-tax) in 2013 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 DOE Grants and excluding the Cost Cap Exceptions. The change was also due to wholesale base rate increases, effective in April 2013 and May 2014, and an increase in AFUDC equity primarily related to the construction of the Kemper IGCC. These changes were partially offset by a decrease in retail revenues primarily as a result of the 2015 Court decision which required the reversal of revenues recorded in 2013, increases in non-fuel operations and maintenance expenses and interest expense. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

The Company's net income (loss) after dividends on preferred stock was ($476.6) million in 2013 compared to $99.9 million in 2012. The decrease in 2013 was primarily the result of pre-tax charges of $1.1 billion ($680.5 million after-tax) 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 DOE Grants and excluding the Cost Cap Exceptions. These charges were partially offset by an increase in AFUDC equity primarily related to the construction of the Kemper IGCC which began in 2010 and an increase in revenues primarily due to retail and wholesale base rate increases and a retail rate increase related to the Kemper IGCC cost recovery that became effective in April 2013. 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	
	2014	2014	2013
		(in millions)	
Operating revenues	$ 1,242.6	$ 97.5	$ 109.2
Fuel	574.0	82.7	80.0
Purchased power	42.9	(5.4)	(6.8)
Other operations and maintenance	270.7	17.3	24.7
Depreciation and amortization	97.1	5.7	4.9
Taxes other than income taxes	79.1	(1.5)	1.2
Estimated loss on Kemper IGCC	868.0	(234.0)	1,024.0
Total operating expenses	1,931.8	(135.2)	1,128.0
Operating income	(689.2)	232.7	(1,018.8)
Allowance for equity funds used during construction	136.4	14.8	56.8
Interest expense, net of amounts capitalized	(45.3)	(8.8)	(4.4)
Other income (expense), net	(14.1)	(8.1)	(7.3)
Income taxes (benefit)	(285.2)	82.6	(388.4)
Net income (loss)	(327.0)	148.0	(576.5)
Dividends on preferred stock	1.7	—	—
Net income (loss) after dividends on preferred stock	$ (328.7)	$ 148.0	$ (576.5)

Operating Revenues

Operating revenues for 2014 were $1.2 billion, reflecting a $97.5 million increase from 2013. Details of operating revenues were as follows:

	Amount	
	2014	2013
	(in millions)	
Retail — prior year	$ 799.1	$ 747.5
Estimated change resulting from —		
Rates and pricing	(11.5)	18.2
Sales growth (decline)	(1.5)	(0.7)
Weather	2.9	1.2
Fuel and other cost recovery	5.6	32.9
Retail — current year	794.6	799.1
Wholesale revenues —		
Non-affiliates	322.7	293.9
Affiliates	107.2	34.8
Total wholesale revenues	429.9	328.7
Other operating revenues	18.1	17.4
Total operating revenues	$ 1,242.6	$ 1,145.2
Percent change	8.5%	10.5%

Total retail revenues for 2014 decreased $4.5 million, or 0.6%, compared to 2013 primarily as a result of $10.3 million in revenues recorded in 2013 that were reversed in 2014 as a result of the 2015 Court decision. See Note 3 to the financial

statements under "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2015 Mississippi Supreme Court Decision" for additional information. This decrease was partially offset by a PEP base rate increase, effective in March 2013, of $2.8 million and a $4.7 million refund in 2013 related to the annual PEP lookback filing. See Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for additional information. Total retail revenues for 2013 increased $51.6 million, or 6.9%, compared to 2012 primarily as a result of a base rate increase, a rate increase related to Kemper IGCC cost recovery that became effective in April 2013, and higher fuel cost recovery revenues in 2013 compared to 2012.

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. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information. Fuel and other cost recovery revenues increased in 2014 and 2013 compared to prior years primarily as a result of higher recoverable fuel costs.

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.

Wholesale revenues from power sales to non-affiliated utilities, including FERC-regulated MRA sales as well as market-based sales, were as follows:

	2014	2013	2012
		(in millions)	
Capacity and other	$ **160.3**	$ 143.0	$ 122.5
Energy	**162.4**	150.9	133.1
Total non-affiliated	$ **322.7**	$ 293.9	$ 255.6

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 service territory, and the availability of the Southern Company system's generation. Increases and decreases in 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. The Company serves 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 21.9% of the Company's total operating revenues in 2014 and are largely subject to rolling 10-year cancellation notices.

Wholesale revenues from sales to non-affiliates increased $28.8 million, or 9.8%, in 2014 compared to 2013 as a result of a $17.3 million increase in base revenues primarily resulting from wholesale base rate increases effective April 1, 2013 and May 1, 2014 and an $11.5 million increase in energy revenues, of which $10.0 million was associated with an increase in KWH sales and $1.5 million was associated with higher fuel prices. Wholesale revenues from sales to non-affiliates increased $38.4 million, or 15.0%, in 2013 compared to 2012 as a result of a $20.5 million increase in base revenues primarily resulting from a wholesale base rate increase effective April 1, 2013 and a $17.8 million increase in energy revenues, of which $14.0 million was associated with higher fuel prices and $3.8 million was associated with an increase in KWH sales.

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 increased $72.4 million, or 208.3%, in 2014 compared to 2013 primarily due to a $74.6 million increase in energy revenues of which $69.3 million was associated with an increase in KWH sales and $5.3 million was associated with higher prices, partially offset by a decrease in capacity revenues of $2.2 million. Wholesale revenues from sales to affiliates increased $18.4 million, or 112.0%, in 2013 compared to 2012 due to a $1.3 million increase in capacity revenues and a $17.1 million increase in energy revenues of which $7.2 million was associated with higher prices and $9.9 million was associated with an increase in KWH sales.

Other operating revenues in 2014 increased $0.7 million, or 4.2%, from 2013 primarily due to a $1.3 million increase in transmission revenues, partially offset by a $0.6 million decrease in microwave tower lease revenue and a $0.2 million decrease in miscellaneous revenues from timber and easement sale proceeds. Other operating revenues in 2013 increased $0.8 million, or 4.8%, from 2012 primarily due to a $0.5 million increase in transmission revenues and a $0.3 million increase in miscellaneous revenue from timber and easement sale proceeds.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2014 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2014	2014	2013	2014	2013
	(in millions)				
Residential	**2,126**	**1.8%**	2.0%	**(2.3)%**	—%
Commercial	**2,859**	**(0.2)**	(1.7)	**0.1**	(1.1)
Industrial	**4,943**	**4.3**	0.8	**4.3**	0.8
Other	**41**	**1.1**	4.0	**1.1**	4.0
Total retail	**9,969**	**2.4**	0.3%	**1.6 %**	0.1%
Wholesale					
Non-affiliated	**4,191**	**6.7**	2.9		
Affiliated	**2,900**	**211.4**	62.8		
Total wholesale	**7,091**	**45.9**	10.7		
Total energy sales	**17,060**	**16.9%**	3.5%		

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 energy sales increased 1.8% in 2014 compared to 2013 due to colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013. Weather-adjusted residential energy sales decreased 2.3% in 2014 compared to 2013 due to lower average usage per customer. Household income, one of the primary drivers of residential customer usage, was flat in 2014. Residential energy sales increased 2.0% in 2013 compared to 2012 due to less mild weather and a slight increase in the number of residential customers in 2013 compared to 2012.

Commercial energy sales decreased 1.7% in 2013 compared to 2012 due to decreased economic activity in 2013 compared to 2012.

Industrial energy sales increased 4.3% in 2014 compared to 2013 due to increased production related to expanded operation by many industrial customers. Industrial energy sales increased 0.8% in 2013 compared to 2012 due to increased usage by larger industrial customers as well as expansions by existing customers.

Wholesale energy sales to non-affiliates increased 6.7% in 2014 compared to 2013 primarily due to increased opportunity sales to the external market as a result of lower system prices. Wholesale energy sales to non-affiliates increased 2.9% in 2013 compared to 2012 primarily due to increased KWH sales to rural electric cooperative associations and municipalities located in southeastern Mississippi resulting from less mild weather in 2013 compared to 2012.

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

Wholesale energy sales to affiliates increased 211.4% in 2014 compared to 2013 primarily due to an increase in the Company's generation, resulting in more energy available to sell to affiliate companies. Wholesale energy sales to affiliates increased 62.8% in 2013 compared to 2012 primarily due to an increase in the Company's generation, resulting in more energy available to sell to affiliate companies.

Fuel and Purchased Power Expenses

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

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

	2014	2013	2012
Total generation *(millions of KWHs)*	**16,881**	13,721	12,750
Total purchased power *(millions of KWHs)*	**886**	1,559	1,961
Sources of generation *(percent)* –			
Coal	**42**	36	26
Gas	**58**	64	74
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**3.96**	4.97	5.09
Gas	**3.37**	3.16	2.90
Average cost of fuel, generated *(cents per net KWH)*	**3.64**	3.87	3.53
Average cost of purchased power *(cents per net KWH)*	**4.85**	3.10	2.81

Fuel and purchased power expenses were $616.9 million in 2014, an increase of $77.3 million, or 14.3%, above the prior year costs. The increase was primarily due to a $114.4 million increase in the total volume of KWHs generated, offset by a $37.1 million decrease in the cost of fuel and purchased power. Fuel and purchased power expenses were $539.6 million in 2013, an increase of $73.2 million, or 15.7%, above the prior year costs. The increase was primarily due to a $55.1 million increase in the total volume of KWHs generated and purchased and an $18.1 million increase in the cost of fuel and 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 fuel cost recovery clauses. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" and Note 1 to the financial statements under "Fuel Costs" for additional information.

Fuel

Fuel expense increased $82.7 million, or 16.8%, in 2014 compared to 2013. The increase was the result of a 24.5% increase in the volume of KWHs generated in 2014, partially offset by a 5.9% decrease in the average cost of fuel per KWH generated. Fuel expense increased $80.0 million, or 19.5%, in 2013 compared to 2012. The increase was the result of a 9.6% increase in the average cost of fuel per KWH generated and a 9.0% increase in the volume of KWHs generated resulting from increased non-territorial sales in 2013 compared to 2012.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates increased $12.1 million, or 210.3%, in 2014 compared to 2013. The increase was primarily the result of a 276.7% increase in the average cost per KWH purchased, partially offset by a 17.6% decrease in the volume of KWHs purchased. Purchased power expense from non-affiliates increased $0.5 million, or 10.2%, in 2013 compared to 2012. The increase was the result of an 8.0% increase in the average cost per KWH purchased and a 2.0% increase in the volume of KWHs purchased. The increase in the average cost per KWH purchased was due to a higher marginal cost of fuel. The increase in the volume of KWHs purchased was due to a lower market cost of available energy compared to the cost of generation.

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

Purchased Power - Affiliates

Purchased power expense from affiliates decreased $17.5 million, or 41.1%, in 2014 compared to 2013. The decrease in 2014 was primarily the result of a 49.5% decrease in the volume of KWHs purchased, offset by a 16.8% increase in the average cost per KWH purchased compared to 2013. Purchased power expense from affiliates decreased $7.3 million, or 14.7%, in 2013 compared to 2012. The decrease was primarily the result of a 24.7% decrease in the volume of KWHs purchased, partially offset by a 13.2% increase in the average cost per KWH purchased compared to 2012.

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 $17.3 million, or 6.8%, in 2014 compared to 2013 primarily due to a $14.1 million increase in employee compensation and benefit expenses and a $6.5 million increase in generation maintenance expenses. These increases in 2014 were partially offset by a $2.0 million decrease in transmission expenses primarily related to overhead line maintenance and vegetation management, and a $0.8 million decrease in customer accounting expenses primarily due to uncollectibles.

Other operations and maintenance expenses increased $24.7 million, or 10.8%, in 2013 compared to 2012 primarily due to a $9.8 million increase in generation maintenance expenses for several planned outages, a $7.6 million increase in administrative and general expenses related to pension expense, a $4.2 million increase in transmission maintenance expenses, a $2.8 million increase in customer accounting primarily due to uncollectibles, and a $2.5 million increase in distribution expenses related to overhead line maintenance and vegetation management. These increases were partially offset by a $2.7 million decrease in labor expenses.

Depreciation and Amortization

Depreciation and amortization increased $5.7 million, or 6.3%, in 2014 compared to 2013 primarily due to a $4.2 million increase related to the reversal of a regulatory deferral associated with the Kemper IGCC municipal franchise taxes, a $2.2 million increase in depreciation related to an increase in assets in service, and a $2.2 million increase resulting from a regulatory deferral associated with the purchase of Plant Daniel Units 3 and 4. These increases were partially offset by a $3.7 million decrease associated with a wholesale revenue requirement adjustment.

Depreciation and amortization increased $4.9 million, or 5.7%, in 2013 compared to 2012 primarily due to a $4.3 million increase in ECO Plan amortization, a $2.0 million increase in amortization resulting from a regulatory deferral associated with the purchase of Plant Daniel Units 3 and 4, and a $1.6 million increase in depreciation resulting from an increase in plant in service. These increases were partially offset by a $2.1 million decrease in amortization primarily resulting from a regulatory deferral associated with the Kemper IGCC and a $0.7 million decrease in amortization resulting from a regulatory deferral associated with the capital lease related to the Kemper IGCC air separation unit.

See Note 1 to the financial statements under "Depreciation and Amortization" and Note 3 to the financial statements under "FERC Matters," "Retail Regulatory Matters – Performance Evaluation Plan," and " – Environmental Compliance Overview Plan" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes decreased $1.5 million, or 2.0%, in 2014 compared to 2013 primarily as a result of a $6.0 million decrease in franchise taxes, partially offset by a $3.2 million increase in ad valorem taxes and a $1.3 million increase in payroll taxes. Taxes other than income taxes increased $1.2 million, or 1.6%, in 2013 compared to 2012 primarily as a result of a $3.5 million increase in franchise taxes, partially offset by a $2.1 million decrease in ad valorem taxes and a $0.2 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 $868.0 million and $1.1 billion were recorded in 2014 and 2013, 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 DOE Grants and excluding the Cost Cap Exceptions.

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 $14.8 million, or 12.2%, in 2014 as compared to 2013 and $56.8 million, or 87.7%, in 2013 as compared to 2012. These increases in 2014 and 2013 were primarily due to CWIP related to the Company's Kemper IGCC. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Allowance for Funds Used During

Construction" 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 $8.8 million, or 24.2%, in 2014 compared to 2013, primarily due to an $11.0 million increase in interest expense resulting from the receipt of $75.0 million and $50.0 million interest-bearing refundable deposits from SMEPA in January 2014 and October 2014, respectively, related to its pending purchase of an undivided interest in the Kemper IGCC, an $8.2 million increase in interest expense on the regulatory liability related to the Kemper IGCC rate recovery, a $4.6 million increase in interest expense primarily associated with the issuances of long-term debt in 2014, and a $2.8 million increase in other interest expense. These increases in 2014 over the prior year were partially offset by a $14.6 million increase in capitalized interest resulting from carrying costs associated with the Kemper IGCC and a $3.2 million decrease in interest expense primarily associated with the redemption of long-term debt in late 2013.

Interest expense, net of amounts capitalized decreased $4.4 million, or 10.7%, in 2013 compared to 2012, primarily due to a $20.1 million increase in capitalized interest resulting from AFUDC debt associated with the Kemper IGCC and a $2.6 million decrease in interest expense associated with the redemption of long-term debt in 2013. These decreases in 2013 from the prior year were partially offset by a $12.2 million increase in interest expense primarily associated with the issuances of new long-term debt in 2013, a $4.0 million increase in interest expense resulting from the receipt of a $150.0 million interest-bearing refundable deposit from SMEPA in March 2012 related to its pending purchase of an undivided interest in the Kemper IGCC, and a $2.7 million increase in interest expense in the regulatory liability related to the Kemper IGCC rate recovery.

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle – Proposed Sale of Undivided Interest to SMEPA" for more information.

Other Income (Expense), Net

Other income (expense), net decreased $8.1 million, or 133.7%, in 2014 compared to 2013 primarily due to $7.0 million associated with the Sierra Club settlement and a $1.1 million increase in consulting fees. Other income (expense), net decreased $7.3 million in 2013 compared to 2012 primarily due to a $5.9 million increase in consulting fees. See "Other Matters – Sierra Club Settlement Agreement" herein and Note 3 to the financial statements under "Other Matters – Sierra Club Settlement Agreement" for additional information.

Income Taxes (Benefit)

Income taxes (benefit) increased $82.6 million, or 22.5%, in 2014 compared to 2013 and decreased $388.4 million in 2013 compared to 2012 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 electricity to retail customers within its traditional service area 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 – Electric Utility Regulation" herein, and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to prevail against legal challenges associated with the Kemper IGCC, recover its prudently-incurred costs in a timely manner during a time of increasing costs and the completion and subsequent operation of the Kemper IGCC and the Plant Daniel scrubber project as well as other ongoing construction projects.

Future earnings in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, 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. Changes in regional and global economic conditions may impact sales for the Company, as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis or through market-based contracts. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. 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.

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against Alabama Power alleging violations of the New Source Review provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by the Company. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. See Note 3 to the financial statements under "Environmental Matters – New Source Review Actions" for additional information. The ultimate outcome of these matters cannot be determined at this time.

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; 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 2014, the Company had invested approximately $523 million in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $118 million, $104 million, and $52 million for 2014, 2013, and 2012, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $154 million from 2015 through 2017, with annual totals of approximately $94 million, $25 million, and $35 million for 2015, 2016, and 2017, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information.

The Company'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 and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, 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 Note 3 to the financial statements under "Other Matters – Sierra Club Settlement Agreement" for additional information.

Compliance with any new federal or state legislation or regulations relating to air quality, water, CCR, global climate change, 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. Since 1990, the Company has spent approximately $393 million in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2012, the EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015 up to April 16, 2016 for affected units for which extensions have been granted. On November 25, 2014, the U.S. Supreme Court granted a petition for review of the final MATS rule.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard (NAAQS). On December 17, 2014, the EPA published a proposed rule to further reduce the current eight-hour ozone standard. The EPA is required by federal court order to complete this rulemaking by October 1, 2015. Finalization of a lower eight-hour ozone standard could result in the designation of new ozone nonattainment areas within the Company's service territory.

Final revisions to the NAAQS for sulfur dioxide (SO_2), which established a new one-hour standard, became effective in 2010. No areas within the Company's service territory have been designated as nonattainment under this rule. However, the EPA has announced plans to make additional designation decisions for SO_2 in the future, which could result in nonattainment designations for areas within the Company's service territory. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

On February 13, 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 co-owned by the Company. In March 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 affected units, including units co-owned by the Company.

The Company's service territory is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I beginning in 2015 and Phase II beginning in 2017. In 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety, but on April 29, 2014, the U.S. Supreme Court overturned that decision and remanded the case back to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The U.S. Court of Appeals for the District of Columbia Circuit granted the EPA's motion to lift the stay of the rule, and the first phase of CSAPR took effect on January 1, 2015.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology to certain sources, including fossil fuel-fired generating facilities, built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter.

In 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units), during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

In February 2013, the EPA proposed a rule that would require certain states to revise 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 EPA proposed to supplement the 2013 proposed rule on September 17, 2014, making it more stringent. The EPA has entered into a settlement agreement requiring it to finalize the proposed rule by May 22, 2015. The proposed rule would require states subject to the rule (including Alabama and Mississippi) to revise their SSM provisions within 18 months after issuance of the final 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. The impacts of the eight-hour ozone and SO_2 NAAQS, the Alabama opacity rule, CSAPR, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the

Company cannot be determined at this time and will depend on the specific provisions of the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. These regulations could result in significant additional 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.

See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Compliance Overview Plan" and "Other Matters – Sierra Club Settlement Agreement" 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 on October 14, 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

In June 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing revised technology-based limits for certain wastestreams from steam electric power plants and best management practices for CCR surface impoundments. The EPA has entered into a consent decree requiring it to finalize revisions to the steam electric effluent guidelines by September 30, 2015. The ultimate impact of the rule will also depend on the specific technology requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

On April 21, 2014, the EPA and the U.S. Army Corps of Engineers jointly published a proposed rule to revise the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs, which would significantly expand the scope of federal jurisdiction under the CWA. In addition, the rule as proposed could have significant impacts on economic development projects which could affect customer demand growth. The ultimate impact of the proposed rule will depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time. If finalized as proposed, 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.

These proposed and final water quality regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

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.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate 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 mandate 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 mandated closure of a CCR Unit. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $64 million and ongoing post-closure care of approximately $12 million. The Company will record asset retirement obligations (ARO) for the estimated closure costs required under the CCR Rule during 2015. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

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 properties. 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 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 2014, the EPA published three sets of proposed standards that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. On January 8, 2014, the EPA published proposed standards for new units, and, on June 18, 2014, the EPA published proposed standards governing existing units, known as the Clean Power Plan, and separate standards governing CO_2 emissions from modified and reconstructed units. The EPA's proposed Clean Power Plan establishes guidelines for states to develop plans to address CO_2 emissions from existing fossil fuel-fired electric generating units. The EPA's proposed guidelines establish state-specific interim and final CO_2 emission rate goals to be achieved between 2020 and 2029 and 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. 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 market-based contracts.

The Southern Company system filed comments on the EPA's proposed Clean Power Plan on December 1, 2014. These comments addressed legal and technical issues in addition to providing a preliminary estimated cost of complying with the proposed guidelines utilizing one of the EPA's compliance scenarios. Costs associated with this proposal could be significant to the utility industry and the Southern Company system. However, the ultimate financial and operational impact of the proposed Clean Power Plan on the Southern Company system cannot be determined at this time and will depend upon numerous known and unknown factors. Some of the unknown factors include: the structure, timing, and content of the EPA's final guidelines; individual state implementation of these guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

Over the past several years, the U.S. Congress has also considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2013 greenhouse gas emissions were approximately 10 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2014 greenhouse gas emissions on the same basis is approximately 11 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

In May 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. See Note 3 to the financial statements under "FERC Matters" for more information.

On March 31, 2014, the Company reached a settlement agreement with its wholesale customers and filed a request with the FERC for an increase in the MRA cost-based electric tariff. The settlement agreement, accepted by the FERC on May 20, 2014, provides that base rates under the MRA cost-based electric tariff will increase approximately $10.1 million annually, with revised rates effective for services rendered beginning May 1, 2014.

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 the Kemper IGCC, 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 March 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.

Energy Efficiency

In July 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 June 3, 2014, the Mississippi PSC approved the Company's 2014 Energy Efficiency Quick Start Plan filing, which includes a portfolio of energy efficiency programs. On October 20, 2014, the Company filed a revised compliance filing, which proposed an increase of $6.7 million in retail revenues for the period December 2014 through December 2015. The Mississippi PSC approved the revised filing on November 4, 2014.

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 projected revenue requirement, and the PEP lookback filing, which is filed after 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 May 2013, the MPUS contested the Company's PEP lookback filing for 2012, which indicated a refund due to customers of $4.7 million. Unresolved matters related to certain costs included in the 2010 PEP lookback filing, which are currently under review, also impact the 2012 PEP lookback filing.

In March 2013, the Mississippi PSC approved the projected PEP filing for 2013, which resulted in a rate increase of 1.9%, or $15.3 million, annually, effective March 19, 2013. The Company may be entitled to $3.3 million in additional revenues related to 2013 as a result of the late implementation of the 2013 PEP rate increase.

On March 18, 2014, the Company submitted its annual PEP lookback filing for 2013, which indicated no surcharge or refund. On March 31, 2014, the Mississippi PSC suspended the filing to allow more time for review.

On June 3, 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.

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 are scheduled to be placed in service in September and November 2015, respectively. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. On August 1, 2014, the Company entered into a settlement agreement with

the Sierra Club (Sierra Club Settlement Agreement) that, among other things, requires 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. 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. 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, and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) and begin operating those units solely on natural gas no later than April 2016. On August 28, 2014, the Chancery Court of Harrison County, Mississippi dismissed the Sierra Club's appeal related to the CPCN to construct scrubbers on Plant Daniel Units 1 and 2.

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. This request was made to minimize the potential rate impact to customers arising from pending and final environmental regulations which may require the premature retirement of some generating units. As of December 31, 2014, $5.6 million of Plant Greene County costs and $2.0 million of costs related to Plant Watson have been reclassified as a regulatory asset. These costs are expected to be recovered through the ECO plan and other existing cost recovery mechanisms. Additional costs associated with the remaining net book value of coal-related equipment will be reclassified to a regulatory asset at the time of retirement for Plants Watson and Greene County in 2015 and 2016, respectively. Approved regulatory asset costs will be amortized over a period to be determined by the Mississippi PSC. As a result, these decisions are not expected to have a material impact on the Company's financial statements.

See Note 3 to the financial statements under "Other Matters – Sierra Club Settlement Agreement" for additional information.

On February 25, 2015, the Company submitted its annual ECO filing for 2015, which indicated an annual increase in revenues of approximately $8.1 million.

The ultimate outcome of these matters 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 most recent filing occurred on November 17, 2014. On January 13, 2015, the Mississippi PSC approved the 2015 retail fuel cost recovery factor, effective January 21, 2015. The retail fuel cost recovery factor will result in an annual increase of approximately $7.9 million. At December 31, 2014, the amount of under-recovered retail fuel costs included in the balance sheets was $2.5 million compared to a $14.5 million over-recovered balance at December 31, 2013.

The Company also has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2015, the wholesale MRA fuel rate decreased resulting in an annual decrease of $1.1 million. Effective February 1, 2015, the wholesale MB fuel rate decreased, resulting in an annual decrease of $0.1 million. At December 31, 2014, the amount of over-recovered wholesale MRA fuel costs included in the balance sheets was $0.2 million compared to an over-recovered balance of $7.3 million at December 31, 2013. At December 31, 2014, the amount of over-recovered wholesale MB fuel costs included in the balance sheets was immaterial compared to an over-recovered balance of $0.3 million at December 31, 2013. In addition, at December 31, 2014, the amount of over-recovered MRA emissions allowance cost included in the balance sheets was $0.3 million compared to a $3.8 million under-recovered balance at December 31, 2013. 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 May 6, 2014, the Mississippi PSC approved the Company's annual ad valorem tax adjustment factor filing for 2014, in which the Company requested an annual rate increase of 0.38%, or $3.6 million in annual retail revenues, primarily due to an increase in property tax rates.

See RESULTS OF OPERATIONS – "Taxes Other Than Income Taxes" herein for additional information.

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. In the Court decision, the Court declined to rule on the constitutionality of the Baseload Act. See "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" and " – 2015 Mississippi Supreme Court Decision" herein for additional information.

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

Construction of the Kemper IGCC is nearing completion and start-up activities will continue until the Kemper IGCC is placed in service. The Kemper IGCC will utilize an IGCC technology with an output capacity of 582 MWs. 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. In connection with the Kemper IGCC, the Company constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the planned 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 $245.3 million of 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 on natural gas on August 9, 2014 and continues to focus on completing the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, for which the in-service date is currently expected to occur in the first half of 2016.

Recovery of the Kemper IGCC costs subject to the cost cap and the Cost Cap Exceptions remain subject to review and approval by the Mississippi PSC. The Company's Kemper IGCC 2010 project estimate, current cost estimate (which includes the impacts of the Court's decision), and actual costs incurred as of December 31, 2014, as adjusted for the Court's decision, are as follows:

Cost Category	2010 Project Estimate[f]	Current Estimate	Actual Costs at 12/31/2014
		(in billions)	
Plant Subject to Cost Cap[a]	$ 2.40	$ 4.93	**$ 4.23**
Lignite Mine and Equipment	0.21	0.23	**0.23**
CO_2 Pipeline Facilities	0.14	0.11	**0.10**
AFUDC[b][c]	0.17	0.63	**0.45**
Combined Cycle and Related Assets Placed in Service – Incremental[d]	—	0.02	0.00
General Exceptions	0.05	0.10	**0.07**
Deferred Costs[c][e]	—	0.18	**0.12**
Total Kemper IGCC[a][c]	$ 2.97	$ 6.20	**$ 5.20**

(a) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, net of the DOE Grants and excluding the Cost Cap Exceptions. The Current Estimate and Actual Costs include non-incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service on August 9, 2014 that are subject to the $2.88 billion cost cap and excludes post-in-service costs for the lignite mine. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" for additional information.

(b) The Company's original estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC in 2012 as described in "Rate Recovery of Kemper IGCC Costs."

(c) Amounts in the Current Estimate reflect estimated costs through March 31, 2016.

(d) Incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service on August 9, 2014, net of costs related to energy sales. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" for additional information.

(e) The 2012 MPSC CPCN Order approved deferral of non-capital Kemper IGCC-related costs during construction as described in "Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities."

(f) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities which was approved in 2011 by the Mississippi PSC.

Of the total costs, including post-in-service costs for the lignite mine, incurred as of December 31, 2014, $3.04 billion was included in property, plant, and equipment (which is net of the DOE Grants and estimated probable losses of $2.05 billion), $1.8 million in other property and investments, $44.7 million in fossil fuel stock, $32.5 million in materials and supplies, $147.7 million in other regulatory assets, $11.6 million in other deferred charges and assets, and $23.6 million in AROs in the balance sheet, with $1.1 million previously expensed.

The Company does not intend to seek any rate recovery or joint owner contributions for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. The Company recorded pre-tax charges to income for revisions to the cost estimate of $868.0 million ($536.0 million after tax), $1.10 billion ($680.5 million after tax), and $78.0 million ($48.2 million after tax) in 2014, 2013 and 2012, respectively. The increases to the cost estimate in 2014 primarily reflected costs related to extension of the project's schedule to ensure the required time for start-up activities and operational readiness, completion of construction, additional resources during start-up, and ongoing construction support during start-up and commissioning activities. The current estimate includes costs through March 31, 2016. Any further extension of the in-service date is currently estimated to result in additional base costs of approximately $25 million to $30 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. Any further extension of the in-service date with respect to the Kemper IGCC 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 $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees, which are being deferred as regulatory assets and are estimated to total approximately $7 million per month.

Any further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements,

operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (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). In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the Company's statements of operations and these changes could be material.

Rate Recovery of Kemper IGCC Costs

See "FERC Matters" for additional information regarding the Company's MRA cost-based tariff relating to recovery of a portion of the Kemper IGCC costs from the Company's wholesale customers. Rate recovery of the retail portion of the Kemper IGCC is subject to the jurisdiction of the Mississippi PSC. See Note 3 to the financial statements under "Retail Regulatory Matters – Baseload Act" for additional information. See "Income Tax Matters" herein for additional tax information related to the Kemper IGCC.

The ultimate outcome of the rate recovery matters discussed herein, including the resolution of legal challenges, determinations of prudency, and the specific manner of recovery of prudently-incurred costs, cannot be determined at this time, but could have a material impact on the Company's results of operations, financial condition, and liquidity.

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 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 evaluation of the Rate Mitigation Plan (defined below) and other related proceedings during 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.

2013 Settlement Agreement

In January 2013, the Company entered into a settlement agreement with the Mississippi PSC that, among other things, established 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. The 2013 Settlement Agreement also allowed the Company to secure alternate financing for costs not otherwise recovered in any Mississippi PSC rate proceedings contemplated by the 2013 Settlement Agreement. The Court found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. See "2015 Mississippi Supreme Court Decision" below for additional information.

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 February 2013. The Company's intent under the 2013 Settlement Agreement was to securitize (1) prudently-incurred costs in excess of the certificated cost estimate and up to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, (2) accrued AFUDC, and (3) other prudently-incurred costs, which include carrying costs from the estimated in-service date until securitization is finalized and other costs not included in the Rate Mitigation Plan as approved by the Mississippi PSC.

The Court's decision did not impact the Company's ability to utilize alternate financing through securitization, the 2012 MPSC CPCN Order, or the February 2013 legislation. See "2015 Mississippi Supreme Court Decision" below for additional information.

2013 MPSC Rate Order

Consistent with the terms of the 2013 Settlement Agreement, in March 2013, the Mississippi PSC issued the 2013 MPSC 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. For the period from March 2013 through December 31, 2014, $257.2 million had been collected primarily to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service.

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 the in-service date. The Company will not record AFUDC on any additional costs of the Kemper IGCC that exceed the $2.88 billion cost cap, except for Cost Cap Exception amounts. The Company will continue to record AFUDC and collect and defer the approved rates through the in-service date until directed to do otherwise by the Mississippi PSC.

On August 18, 2014, the Company provided an analysis of the costs and benefits of placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service, including the expected accounting treatment. The Company's analysis requested, among other things, confirmation of the Company's accounting treatment by the Mississippi PSC of the continued collection of rates as prescribed by the 2013 MPSC Rate Order, with the current recognition as revenue of the related equity return on all assets placed in service and the deferral of all remaining rate collections under the 2013 MPSC Rate Order to a regulatory liability account. See "2015 Mississippi Supreme Court Decision" for additional information regarding the decision of the Court which would discontinue the collection of, and require the refund of, all amounts previously collected under the 2013 MPSC Rate Order.

In addition, the Company's August 18, 2014 filing with the Mississippi PSC requested confirmation of the Company's accounting treatment by the Mississippi PSC of the continued accrual of AFUDC through the in-service date of the remainder of the Kemper IGCC and the deferral of operating costs for the combined cycle as regulatory assets. Under the Company's proposal, non-incremental costs that would have been incurred whether or not the combined cycle was placed in service would be included in a regulatory asset and would continue to be subject to the $2.88 billion cost cap. Additionally, incremental costs that would not have been incurred if the combined cycle had not gone into service would be included in a regulatory asset and would not be subject to the cost cap because these costs are incurred to support operation of the combined cycle. All energy revenues associated with the combined cycle variable operating and maintenance expenses would be credited to this regulatory asset. See "Regulatory Assets and Liabilities" for additional information. Any action by the Mississippi PSC that is inconsistent with the treatment requested by the Company could have a material impact on the results of operations, financial condition, and liquidity of the Company.

2015 Mississippi Supreme Court Decision

On February 12, 2015, the Court issued its decision in the legal challenge to the 2013 MPSC Rate Order filed by Thomas A. Blanton. 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. The Court's ruling remands the matter to the Mississippi PSC to (1) fix by order the rates that were in existence prior to the 2013 MPSC Rate Order, (2) fix no rate increases until the Mississippi PSC is in compliance with the Court's ruling, and (3) enter an order refunding amounts collected under the 2013 MPSC Rate Order. Through December 31, 2014, the Company had collected $257.2 million through rates under the 2013 MPSC Rate Order. Any required refunds would also include carrying costs. The Court's decision will become legally effective upon the issuance of a mandate to the Mississippi PSC. Absent specific instruction from the Court, the Mississippi PSC will determine the method and timing of the refund. The Company is reviewing the Court's decision and expects to file a motion for rehearing which would stay the Court's mandate until either the case is reheard and decided or seven days after the Court issues its order denying the Company's request for rehearing. The Company is also evaluating its regulatory options.

Rate Mitigation Plan

In March 2013, the Company, in compliance with the 2013 MPSC Rate Order, filed a revision to the proposed rate recovery plan with the Mississippi PSC for the Kemper IGCC for cost recovery through 2020 (Rate Mitigation Plan), which is still under review by the Mississippi PSC. The revenue requirements set forth in the Rate Mitigation Plan assume the sale of a 15% undivided interest in the Kemper IGCC to SMEPA and utilization of bonus depreciation, which currently requires that the related long-term asset be placed in service in 2015. In the Rate Mitigation Plan, the Company proposed recovery of an annual revenue requirement of approximately $156 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. The 2013 MPSC Rate Order, which increased rates beginning in March 2013, was integral to the Rate Mitigation Plan, which contemplates amortization of the regulatory liability balance at the in-service date to be used to mitigate customer rate impacts through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the Rate Mitigation Plan, the Company proposed annual rate recovery to remain the same from 2014 through 2020, with the proposed revenue requirement approximating the forecasted cost of service for the period 2014 through 2020. Under the Company's proposal, to the extent the actual annual cost of service differs from the approved forecast for certain items, the difference would be deferred as a regulatory asset or liability, subject to accrual of carrying costs, and would be included in the next year's rate recovery calculation. If any deferred balance remains at the end of 2020, the Mississippi PSC

would review the amount and, if approved, determine the appropriate method and period of disposition. See "Regulatory Assets and Liabilities" and "Income Tax Matters" for additional information.

To the extent that refunds of amounts collected under the 2013 MPSC Rate Order are required on a schedule different from the amortization schedule proposed in the Rate Mitigation Plan, the customer billing impacts proposed under the Rate Mitigation Plan would no longer be viable. See "2015 Mississippi Supreme Court Decision" above for additional information.

In the event that the Mirror CWIP regulatory liability is refunded to customers prior to the in-service date of the Kemper IGCC and is, therefore, not available to mitigate rate impacts under the Rate Mitigation Plan, the Mississippi PSC does not approve a refund schedule that facilitates rate mitigation, or the Company withdraws the Rate Mitigation Plan, the Company would seek rate recovery through alternate means, which could include a traditional rate case.

In addition to current estimated costs at December 31, 2014 of $6.20 billion, the Company anticipates that it will incur additional costs after the Kemper IGCC in-service date until the Kemper IGCC cost recovery approach is finalized. These costs include, but are not limited to, regulatory costs and additional carrying costs which could be material. Recovery of these costs would be subject to approval by the Mississippi PSC.

Prudence Reviews

The Mississippi PSC's review of Kemper IGCC costs is ongoing. On August 5, 2014, the Mississippi PSC ordered that a consolidated prudence determination of all Kemper IGCC costs be completed after the entire project has been placed in service and has demonstrated availability for a reasonable period of time as determined by the Mississippi PSC and the MPUS. The Mississippi PSC has encouraged the parties to work in good faith to settle contested issues and the Company is working to reach a mutually acceptable resolution. As a result of the Court's decision, the Company intends to request that the Mississippi PSC reconsider its prudence review schedule. See "2015 Mississippi Supreme Court Decision" 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.

On August 18, 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. As of December 31, 2014, the regulatory asset balance associated with the Kemper IGCC was $147.7 million. The projected balance at March 31, 2016 is estimated to total approximately $269.8 million. The amortization period of 40 years proposed by the Company for any such costs approved for recovery remains subject to approval by the Mississippi PSC.

The 2013 MPSC Rate Order approved 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. On February 12, 2015, the Court ordered the Mississippi PSC to refund Mirror CWIP and to fix by order the rates that were in existence prior to the 2013 MPSC Rate Order. The Company is deferring the collections under the approved rates in the Mirror CWIP regulatory liability until otherwise directed by the Mississippi PSC. The Company is also accruing carrying costs on the unamortized balance of the Mirror CWIP regulatory liability for the benefit of retail customers. As of December 31, 2014, the balance of the Mirror CWIP regulatory liability, including carrying costs, was $270.8 million.

See "2015 Mississippi Supreme Court Decision" for additional information.

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 will own 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 has entered into agreements with Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tengrys, LLC, pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC. The agreements with Denbury and Treetop provide termination rights in the event that the Company does not satisfy its contractual obligation with respect to deliveries of captured CO_2 by May 11, 2015. While the Company has received no indication from either Denbury or Treetop of their intent to terminate their respective agreements, any termination could result in a material reduction in future chemical product sales revenues and could have a material financial impact on the Company to the extent the Company is not able to enter into other similar contractual arrangements.

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

Proposed Sale of Undivided Interest to SMEPA

In 2010, the Company and SMEPA entered into an APA whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. In 2012, the Mississippi PSC approved the sale and transfer of the 17.5% undivided interest in the Kemper IGCC to SMEPA. Later in 2012, the Company and SMEPA signed an amendment to the APA whereby SMEPA reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC. In March 2013, the Company and SMEPA signed an amendment to the APA whereby the Company and SMEPA agreed to amend the power supply agreement entered into by the parties in 2011 to reduce the capacity amounts to be received by SMEPA by half (approximately 75 MWs) at the sale and transfer of the undivided interest in the Kemper IGCC to SMEPA. Capacity revenues under the 2011 power supply agreement were $16.7 million in 2014. In December 2013, the Company and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2014.

By letter agreement dated October 6, 2014, the Company and SMEPA agreed in principle on certain issues related to SMEPA's proposed purchase of a 15% undivided interest in the Kemper IGCC. The letter agreement contemplated certain amendments to the APA, which the parties anticipated to be incorporated into the APA on or before December 31, 2014. The parties agreed to further amend the APA as follows: (1) the Company agreed to cap at $2.88 billion the portion of the purchase price payable for development and construction costs, net of the Cost Cap Exceptions, title insurance reimbursement, and AFUDC and/or carrying costs through the Closing Commitment Date (defined below); (2) SMEPA agreed to close the purchase within 180 days after the date of the execution of the amended APA or before the Kemper IGCC in-service date, whichever occurs first (Closing Commitment Date), subject only to satisfaction of certain conditions; and (3) AFUDC and/or carrying costs will continue to be accrued on the capped development and construction costs, the Cost Cap Exceptions, and any operating costs, net of revenues until the amended APA is executed by both parties, and thereafter AFUDC and/or carrying costs and payment of interest on SMEPA's deposited money will be suspended and waived provided closing occurs by the Closing Commitment Date. The letter agreement also provided for certain post-closing adjustments to address any differences between the actual and the estimated amounts of post-in-service date costs (both expenses and capital) and revenue credits for those portions of the Kemper IGCC previously placed in service.

By letter dated December 18, 2014, SMEPA notified the Company that SMEPA decided not to extend the estimated closing date in the APA or revise the APA to include the contemplated amendments; however, both parties agree that the APA will remain in effect until closing or until either party gives notice of termination.

The closing of this transaction is also conditioned upon execution of a joint ownership and operating agreement, the absence of material adverse effects, receipt of all construction permits, and appropriate regulatory approvals, as well as SMEPA's receipt of Rural Utilities Service (RUS) funding. In 2012, SMEPA received a conditional loan commitment from RUS for the purchase.

In 2012, on January 2, 2014, and on October 9, 2014, the Company received $150 million, $75 million, and $50 million, respectively, of interest-bearing refundable deposits from SMEPA to be applied to the purchase. While the expectation is that these amounts will be applied to the purchase price at closing, the Company would be required to refund the deposits upon the termination of the APA or within 15 days of a request by SMEPA for a full or partial refund. Given the interest-bearing nature of the deposits and SMEPA's ability to request a refund, the deposits have been presented as a current liability in the balance sheet and as financing proceeds in the statement of cash flow. In July 2013, Southern Company entered into an agreement with SMEPA

under which Southern Company has agreed to guarantee the obligations of the Company with respect to any required refund of the deposits.

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

Income Tax Matters

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

Bonus Depreciation

On December 19, 2014, the Tax Increase Prevention Act of 2014 (TIPA) was signed into law. The TIPA retroactively extended several tax credits through 2014 and extended 50% bonus depreciation for property placed in service in 2014 (and for certain long-term production-period projects to be placed in service in 2015). The extension of 50% bonus depreciation had a positive impact on the Company's cash flows and combined with bonus depreciation allowed in 2014 under the American Taxpayer Relief Act of 2012, resulted in approximately $130 million of positive cash flows related to the combined cycle and associated common facilities portion of the Kemper IGCC for the 2014 tax year. The estimated cash flow benefit of bonus depreciation related to TIPA is expected to be approximately $45 million to $50 million for the 2015 tax year.

Investment Tax Credits

The IRS allocated $279.0 million (Phase II) of Internal Revenue Code of 1986, as amended (Internal Revenue Code), Section 48A tax credits to the Company in connection with the Kemper IGCC. Through December 31, 2014, the Company had recorded tax benefits totaling $276.4 million for the Phase II credits, of which approximately $210 million had been utilized through that date. These credits will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC and are dependent upon meeting the IRS certification requirements, including an in-service date no later than April 19, 2016 and 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. The Company currently expects to place the Kemper IGCC in service in the first half of 2016. In addition, a portion of the Phase II tax credits will be subject to recapture upon completion of SMEPA's proposed purchase of an undivided interest in the Kemper IGCC as described above.

Section 174 Research and Experimental Deduction

Southern Company, on behalf of the Company, reduced tax payments for 2014 and included in its 2013 consolidated federal income tax return deductions for research and experimental (R&E) expenditures related to the Kemper IGCC. Due to the uncertainty related to this tax position, the Company recorded an unrecognized tax benefit of approximately $160 million as of December 31, 2014. See Note 5 to the financial statements under "Unrecognized Tax Benefits" 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.

In February 2013, the Company submitted a claim under the Deepwater Horizon Economic and Property Damages Settlement Agreement associated with the oil spill that occurred in April 2010 in the Gulf of Mexico. The ultimate outcome of this matter cannot be determined at this time.

Sierra Club Settlement Agreement

On August 1, 2014, the Company entered into the Sierra Club Settlement Agreement that, among other things, requires the Sierra Club to dismiss or withdraw all pending legal and regulatory challenges of the Kemper IGCC and the scrubber project at Plant Daniel Units 1 and 2. In addition, the Sierra Club agreed to refrain from initiating, intervening in, and/or challenging certain legal and regulatory proceedings for the Kemper IGCC, including, but not limited to, the prudence review, and Plant Daniel for a period of three years from the date of the Sierra Club Settlement Agreement. On August 4, 2014, the Sierra Club filed all of the required motions necessary to dismiss or withdraw all appeals associated with certification of the Kemper IGCC and the Plant Daniel Units 1 and 2 scrubber project, which the applicable courts subsequently granted.

Under the Sierra Club Settlement Agreement, the Company agreed to, among other things, fund a $15 million grant payable over a 15-year period for an energy efficiency and renewable program and contribute $2 million to a conservation fund. In accordance with the Sierra Club Settlement Agreement, the Company paid $7 million in 2014, recognized in other income (expense), net in the statement of operations. 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. 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, and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) and begin operating those units solely on natural gas no later than April 2016. See Note 3 under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

The Company is subject to retail regulation by the 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 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.

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, in accordance with GAAP, 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 financial position, results of operations, or cash flows.

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.

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 in accordance with GAAP 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 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. The Company discounts the future cash flows related to its postretirement benefit plans 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 purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $30.2 million and $5.2 million, respectively. The adoption of new mortality tables will increase net periodic costs related to the Company's pension plans and other postretirement benefit plans in 2015 by $4.1 million and $0.6 million, respectively.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $1.8 million or less change in total annual benefit expense and a $22.7 million or less change in projected obligations.

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 6.91%, 6.89%, and 7.04% for the years ended December 31, 2014, 2013, and 2012, respectively. The AFUDC rate is applied to CWIP consistent with jurisdictional regulatory treatment. AFUDC equity was $136.4 million, $121.6 million, and $64.8 million in 2014, 2013, and 2012, respectively.

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

During 2014, the Company further extended the scheduled in-service date for the Kemper IGCC to the first half of 2016 and 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 DOE Grants and excluding the Cost Cap Exceptions. The Company does not intend to seek any rate recovery or any joint owner contributions for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions.

As a result of the revisions to the cost estimate, the Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC of $70.0 million ($43.2 million after tax) in the fourth quarter 2014, $418.0 million ($258.1 million after tax) in the third quarter 2014, $380.0 million ($234.7 million after tax) in the first quarter 2014, $40.0 million ($24.7 million

after tax) in the fourth quarter 2013, $150.0 million ($92.6 million after tax) in the third quarter 2013, $450.0 million ($277.9 million after tax) in the second quarter 2013, $462.0 million ($285.3 million after tax) in the first quarter 2013, and $78.0 million ($48.2 million after tax) in the fourth quarter 2012. In the aggregate, the Company has incurred charges of $2.05 billion ($1.26 billion after tax) as a result of changes in the cost estimate for the Kemper IGCC through December 31, 2014.

The Company has experienced, and may continue to experience, material changes in the cost estimate for the Kemper IGCC. In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the statements of operations and these changes could be material. Any further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (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 Company's revised cost estimate includes costs through March 31, 2016. Any further extension of the in-service date is currently estimated to result in additional base costs of approximately $25 million to $30 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. Any further extension of the in-service date with respect to the Kemper IGCC 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 $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting fees and legal fees which are being deferred as regulatory assets and are estimated to total approximately $7 million per month.

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 the results of operations, the Company considers these items to be critical accounting estimates. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" herein and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Earnings in 2014 and 2013 were negatively affected by revisions to the cost estimate for the Kemper IGCC and by the Court's decision to reverse the 2013 MPSC Rate order; however, the Company's financial condition remained stable at December 31, 2014 and December 31, 2013 as a result of capital contributions to the Company by Southern Company. The Company's cash requirements primarily consist of funding debt maturities, including $775 million of bank loans maturing in 2015, ongoing operations, capital expenditures, and the potential requirement to refund amounts collected under the 2013 MPSC Rate Order ($257.2 million through December 31, 2014) and additional amounts for associated carrying costs. See FUTURE EARNINGS POTENTIAL – Integrated Coal Gasification Combined Cycle – "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" and " – 2015 Mississippi Supreme Court Decision" herein for additional information. For the three-year period from 2015 through 2017, the Company's capital expenditures and debt maturities are expected to materially exceed operating cash flows. In addition to the Kemper IGCC, projected capital expenditures in that period include investments to maintain existing generation facilities, including the Plant Daniel scrubber project, to add environmental equipment for existing generating units, to add or change fuel sources for certain existing units, and to expand and improve transmission and distribution facilities. Through December 31, 2014, the Company has incurred non-recoverable cash expenditures of $1.3 billion and is expected to incur approximately $702 million in additional non-recoverable cash expenditures through completion of the Kemper IGCC.

In 2014, the Company received $450.0 million in equity contributions and a $220.0 million loan from Southern Company which was repaid on September 29, 2014. In January 2015, the Company received an additional $75.0 million in equity contributions from Southern Company. The Company is currently negotiating to refinance its maturing bank loans and to obtain additional bank loans. The Company also intends to utilize cash from operations and commercial paper and lines of credit as market conditions

permit, as well as, under certain circumstances, equity contributions and/or loans from Southern Company, to fund the Company's short-term capital 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, 2014 as compared to December 31, 2013. In December 2014, the Company voluntarily contributed $33 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015.

Net cash provided from operating activities totaled $734.4 million for 2014, an increase of $286.8 million as compared to the corresponding period in 2013. The increase in net cash provided from operating activities was primarily due to deferred income taxes and Mirror CWIP, net of the Kemper IGCC regulatory deferral, partially offset by a decrease in ITCs received related to the Kemper IGCC, an increase in prepaid income taxes, increases in fossil fuel stock, and an increase in regulatory assets associated with the Kemper IGCC. Net cash provided from operating activities totaled $447.6 million for 2013, an increase of $212.2 million as compared to the corresponding period in 2012. The increase in net cash provided from operating activities was primarily due to an increase in ITCs received related to the Kemper IGCC, increases in rate recovery related to the Kemper IGCC, and decreases in fossil fuel stock, partially offset by a decrease in over-recovered regulatory clause revenues and an increase in regulatory assets associated with the Kemper IGCC.

Net cash used for investing activities totaled $1.3 billion for 2014 primarily due to gross property additions primarily related to the Kemper IGCC and the Plant Daniel scrubber project. Net cash used for investing activities totaled $1.6 billion for 2013 primarily due to gross property additions primarily related to the Kemper IGCC and the Plant Daniel scrubber project, partially offset by proceeds from asset sales.

Net cash provided from financing activities totaled $592.6 million in 2014 primarily due to capital contributions from Southern Company, long-term debt financings, and the receipts of interest bearing refundable deposits related to a pending asset sale, partially offset by redemptions of long-term debt. Net cash provided from financing activities totaled $1.2 billion in 2013 primarily due to an increase in capital contributions from Southern Company and an increase in long-term debt financings, partially offset by redemptions of long-term debt.

Significant balance sheet changes as of December 31, 2014 compared to 2013 included an increase in securities due within one year of $763.9 million and a decrease in long-term debt of $536.6 million, primarily due to bank loans maturing in 2015, as well as an increase in the interest-bearing refundable deposit from SMEPA of $125.0 million. See "Financing Activities" herein for additional information. Total property, plant, and equipment increased $416.6 million and other regulatory assets, deferred increased $184.8 million primarily due to the Kemper IGCC and results of an actuarial study. See "Integrated Coal Gasification Combined Cycle" herein for additional information. Other regulatory liabilities, deferred decreased $81.3 million and Mirror CWIP increased $270.8 million primarily due to the reclassification of Kemper regulatory liabilities. Additional changes included an increase in accrued income taxes of $136.9 million primarily due to R&E tax deductions, an increase in prepaid income taxes of $155.9 million primarily due to ITCs related to the Kemper IGCC and an increase in taxes on Mirror CWIP, a net increase in accumulated deferred income taxes of $194.7 million primarily related to the Kemper combined cycle and associated common facilities placed in service on August 9, 2014 offset by the estimated probable loss on the Kemper IGCC, an increase in employee benefit obligations of $53.1 million, and an increase in deferred charges related to income taxes of $81.8 million. See Note 2 and Note 5 to the financial statements for additional information. Total common stockholder's equity decreased $92.3 million primarily due to the estimated probable loss on the Kemper IGCC partially offset by the receipt of $450.0 million in capital contributions from Southern Company.

The Company's ratio of common equity to total capitalization, including long-term debt due within one year, was 46.1% in 2014 and 49.6% in 2013. See Note 6 to the financial statements for additional information.

Sources of Capital

Except as described herein, the Company plans to obtain the funds required for construction and other purposes from operating cash flows, security issuances, term loans, and/or short-term debt, as well as, under certain circumstances, equity contributions and/or loans from Southern Company. Operating cash flows would be adversely impacted by $156 million annually with the removal of rates implemented under the 2013 MPSC Rate Order. The amount, type, and timing of future financings will depend upon regulatory approval, prevailing market conditions, and other factors, which may include resolution of Kemper IGCC cost recovery. See "Capital Requirements and Contractual Obligations" herein for additional information. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" and " – 2015 Mississippi Supreme Court Decision" included herein for additional information.

The Company received $245.3 million of DOE Grants in prior years that were used for the construction of the Kemper IGCC. An additional $25 million of DOE Grants is expected to be received for commercial operation of the Kemper IGCC. In addition, see FUTURE EARNINGS POTENTIAL – "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, 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 FERC, as well as the amounts registered under the 1933 Act, 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.

As of December 31, 2014, the Company's current liabilities exceeded current assets by approximately $1.3 billion primarily due to $775 million of bank loans maturing in 2015, an interest-bearing refundable deposit from SMEPA, and the potential Mirror CWIP refund. The Company is currently negotiating to refinance its maturing bank loans and to obtain additional bank loans. The Company also intends to utilize cash from operations, and commercial paper and lines of credit as market conditions permit, as well as, under certain circumstances, equity contributions and/or loans from Southern Company, to fund the Company's short-term capital needs. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" herein for additional information.

At December 31, 2014, the Company had approximately $132.5 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2014 were as follows:

Expires				Executable Term-Loans		Due Within One Year	
2015	2016	Total	Unused	One Year	Two Years	Term Out	No Term Out
			(in millions)				
$ 135	$ 165	$ 300	$ 300	$ 25	$ 40	$ 65	$ 70

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

The Company expects to renew its credit arrangements, as needed prior to expiration.

Most of these bank credit arrangements contain covenants that limit debt levels and typically contain 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 specified threshold. The Company is in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowing.

A portion of the $300 million unused credit arrangements with banks is allocated to provide liquidity support to the Company's variable rate 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, 2014 was $40.1 million.

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

The Company had no short-term borrowings in 2012 and 2014. Details of short-term borrowing for 2013 were as follows:

	Commercial Paper at the End of the Period		Commercial Paper During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2013	$—	—%	$23	0.2%	$148

(a) 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 Loans

In January 2014, the Company entered into an 18-month floating rate bank loan bearing interest based on one-month LIBOR. The term loan was for $250 million aggregate principal amount, and the proceeds were used for working capital and other general corporate purposes, including the Company's continuous construction program.

This and other bank loans and the other revenue bonds described below have 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, other hybrid securities, and securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2014, the Company was in compliance with its debt limits.

In addition, this and other bank loans and the other revenue bonds described below contain cross default provisions to other debt (including guarantee obligations) that would be triggered if the Company defaulted on debt above a specified threshold. The Company is currently in compliance with all such covenants.

Other Revenue Bonds

In May 2014 and August 2014, the Mississippi Business Finance Corporation (MBFC) issued $12.3 million and $10.5 million, respectively, aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013A for the benefit of the Company and proceeds were used to reimburse the Company for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility related to the Kemper IGCC. In December 2014, the MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013A of $22.87 million and Series 2013B of $11.25 million were paid at maturity.

Other Obligations

In 2012, January 2014, and October 2014, the Company received $150 million, $75 million, and $50 million, respectively, of interest-bearing refundable deposits from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the sale is closed, the deposits bear interest at the Company's AFUDC rate adjusted for income taxes, which was 10.134% per annum for 2014, 9.932% per annum for 2013, and 9.967% per annum for 2012, and are refundable to SMEPA upon termination of the APA related to such purchase or within 15 days of a request by SMEPA for a full or partial refund. In July 2013, Southern Company entered into an agreement with SMEPA under which Southern Company has agreed to guarantee the obligations of the Company with respect to any required refund of the deposits.

In May 2014, the Company issued a 19-month floating rate promissory note to Southern Company for a loan bearing interest based on one-month LIBOR. This loan was for $220 million aggregate principal amount and the proceeds were used for working capital and other general corporate purposes, including the Company's construction program. This loan was repaid on September 29, 2014.

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 below BBB- and/or Baa3. These contracts are for physical electricity sales, fuel transportation and storage, and energy price risk management. At December 31, 2014, the maximum amount of potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 equaled approximately $280 million. Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

Subsequent to December 31, 2014, Moody's affirmed the senior unsecured debt rating of the Company and revised the ratings outlook for the Company from stable to negative.

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 $815 million of long-term variable interest rate exposure at December 31, 2014 was 0.96%. 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 $8 million at January 1, 2015. 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, 2014 when compared to the year ended December 31, 2013.

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:

	2014 Changes	2013 Changes
	Fair Value	
	(in thousands)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$ (5,478)	$ (16,927)
Contracts realized or settled	(2,655)	11,271
Current period changes[(a)]	(37,231)	178
Contracts outstanding at the end of the period, assets (liabilities), net	$ (45,364)	$ (5,478)

(a) 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:

	2014	2013
	mmBtu Volume	
	(in thousands)	
Total hedge volume	**54,220**	56,440

The weighted average swap contract cost above market prices was approximately $0.84 per mmBtu as of December 31, 2014 and $0.10 per mmBtu as of December 31, 2013. 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, 2014 and 2013, 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. Gains and losses on energy-related derivatives that are designated as cash flow hedges are used to hedge anticipated purchases and sales and 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 operations as incurred and were not material for any year presented. The pre-tax gains and losses reclassified from OCI to revenue and fuel expense were not material for any period presented and are not expected to be material for 2015.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2014 were as follows:

	Fair Value Measurements December 31, 2014			
	Total Fair Value	Maturity		
		Year 1	Years 2&3	Years 4&5
		(in thousands)		
Level 1	$ —	$ —	$ —	$ —
Level 2	(45,364)	(26,227)	(18,620)	(517)
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ (45,364)	$ (26,227)	$ (18,620)	$ (517)

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

The construction program of the Company is currently estimated to be $1.0 billion for 2015, $328 million for 2016, and $221 million for 2017, which includes expenditures related to the construction of the Kemper IGCC of $801 million in 2015 and $132 million in 2016. The amounts related to the construction and start-up of the Kemper IGCC exclude SMEPA's proposed acquisition of a 15% ownership share of the Kemper IGCC for approximately $596 million (including construction costs for all prior periods relating to its proposed ownership interest). Capital expenditures to comply with environmental statutes and regulations included in these estimated amounts are $94 million, $25 million, and $35 million for 2015, 2016, and 2017, respectively. These estimated amounts also include capital expenditures covered under long-term service agreements. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information.

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and – "Integrated Coal Gasification Combined Cycle" 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. 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, 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

	2015	2016-2017	2018-2019	After 2019	Total
			(in thousands)		
Long-term debt[a] —					
Principal	$ 775,000	$ 335,000	$ 125,000	$ 1,032,695	$ 2,267,695
Interest	77,715	132,442	120,904	723,455	1,054,516
Preferred stock dividends[b]	1,733	3,465	3,465	—	8,663
Financial derivative obligations[c]	26,270	18,623	536	—	45,429
Unrecognized tax benefits[d]	164,821	—	—	—	164,821
Operating leases [e]	3,950	2,601	—	—	6,551
Capital leases[f]	2,667	5,741	6,331	64,940	79,679
Purchase commitments —					
Capital[g]	1,016,215	491,886	—	—	1,508,101
Fuel[h]	266,934	299,888	255,396	289,215	1,111,433
Long-term service agreements[i]	27,109	23,367	20,596	128,832	199,904
Pension and other postretirement benefits plans[j]	6,187	13,112	—	—	19,299
Total	$ 2,368,601	$ 1,326,125	$ 532,228	$ 2,239,137	$ 6,466,091

(a) All amounts are reflected based on final maturity dates. The Company plans to continue 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, 2015, 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 three-year period, including capital expenditures and compliance costs associated with environmental regulations. Estimates related to the construction and start-up of the Kemper IGCC exclude SMEPA's proposed acquisition of a 15% ownership share of the Kemper IGCC. At December 31, 2014, 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" 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, 2014.

(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 2014 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, access to sources of capital, projections for the qualified pension plan and postretirement benefit plan, financing activities, completion of construction projects, filings with state and federal regulatory authorities, impact of the TIPA, 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 legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, CCR, and emissions of sulfur, nitrogen, CO_2, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters, the pending EPA civil action, and IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction 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 operational and environmental performance standards, including any PSC requirements 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 actions relating to proposed securitization, Mississippi PSC approval of a rate recovery plan, including the ability to complete the proposed sale of an interest in the Kemper IGCC to SMEPA, the ability to utilize bonus depreciation, which currently requires that assets be placed in service in 2015, and satisfaction of requirements to utilize ITCs and grants;
- Mississippi PSC review of the prudence of Kemper IGCC costs;
- the ultimate outcome and impact of the February 2015 decision of the Mississippi Supreme Court and any further legal or regulatory proceedings regarding any settlement agreement between the Company and the Mississippi PSC, the March 2013 rate order regarding retail rate increases, or the Baseload Act;

- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

[This page intentionally left blank]

STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2014, 2013, and 2012
Mississippi Power Company 2014 Annual Report

	2014	2013	2012
		(in thousands)	
Operating Revenues:			
Retail revenues	$ 794,643	$ 799,139	$ 747,453
Wholesale revenues, non-affiliates	322,659	293,871	255,557
Wholesale revenues, affiliates	107,210	34,773	16,403
Other revenues	18,099	17,374	16,583
Total operating revenues	1,242,611	1,145,157	1,035,996
Operating Expenses:			
Fuel	573,936	491,250	411,226
Purchased power, non-affiliates	17,848	5,752	5,221
Purchased power, affiliates	25,096	42,579	49,907
Other operations and maintenance	270,669	253,329	228,675
Depreciation and amortization	97,120	91,398	86,510
Taxes other than income taxes	79,112	80,694	79,445
Estimated loss on Kemper IGCC	868,000	1,102,000	78,000
Total operating expenses	1,931,781	2,067,002	938,984
Operating Income (Loss)	(689,170)	(921,845)	97,012
Other Income and (Expense):			
Allowance for equity funds used during construction	136,436	121,629	64,793
Interest expense, net of amounts capitalized	(45,322)	(36,481)	(40,838)
Other income (expense), net	(14,097)	(6,030)	1,264
Total other income and (expense)	77,017	79,118	25,219
Earnings (Loss) Before Income Taxes	(612,153)	(842,727)	122,231
Income taxes (benefit)	(285,205)	(367,835)	20,556
Net Income (Loss)	(326,948)	(474,892)	101,675
Dividends on Preferred Stock	1,733	1,733	1,733
Net Income (Loss) After Dividends on Preferred Stock	$ (328,681)	$ (476,625)	$ 99,942

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

STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2014, 2013, and 2012
Mississippi Power Company 2014 Annual Report

	2014	2013	2012
		(in thousands)	
Net Income (Loss)	**$ (326,948)**	$ (474,892)	$ 101,675
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $-, and $(296) respectively	**—**	—	(479)
Reclassification adjustment for amounts included in net income, net of tax of $526, $526, and $411, respectively	**849**	849	663
Total other comprehensive income (loss)	**849**	849	184
Comprehensive Income (Loss)	**$ (326,099)**	$ (474,043)	$ 101,859

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2014, 2013, and 2012
Mississippi Power Company 2014 Annual Report

	2014	2013	2012
		(in thousands)	
Operating Activities:			
Net income (loss)	$ (326,948)	$ (474,892)	$ 101,675
Adjustments to reconcile net income (loss) to net cash provided from operating activities —			
Depreciation and amortization, total	104,422	92,465	86,981
Deferred income taxes	145,417	(396,400)	17,688
Investment tax credits received	(38,366)	144,036	82,464
Allowance for equity funds used during construction	(136,436)	(121,629)	(64,793)
Pension, postretirement, and other employee benefits	(28,899)	13,953	(35,425)
Hedge settlements	—	—	(15,983)
Stock based compensation expense	2,903	2,510	2,084
Regulatory assets associated with Kemper IGCC	(71,816)	(35,220)	(15,445)
Estimated loss on Kemper IGCC	868,000	1,102,000	78,000
Kemper regulatory deferral	—	90,524	—
Other, net	14,022	14,585	10,516
Changes in certain current assets and liabilities —			
-Receivables	(19,065)	(25,001)	(6,589)
-Under recovered regulatory clause revenues	(2,471)	—	—
-Fossil fuel stock	13,121	63,093	(36,206)
-Materials and supplies	(15,496)	(11,087)	(3,473)
-Prepaid income taxes	(50,457)	16,644	(3,852)
-Other current assets	(3,940)	(4,363)	(19,851)
-Other accounts payable	32,661	12,693	8,814
-Accrued interest	29,349	16,768	17,627
-Accrued taxes	39,392	11,141	13,768
-Accrued compensation	17,008	(6,382)	(183)
-Over recovered regulatory clause revenues	(17,826)	(58,979)	16,836
-Mirror CWIP	180,255	—	—
-Other current liabilities	(446)	1,109	757
Net cash provided from operating activities	734,384	447,568	235,410
Investing Activities:			
Property additions	(1,257,440)	(1,640,782)	(1,620,047)
Investment in restricted cash	(10,548)	—	—
Distribution of restricted cash	10,548	—	—
Cost of removal net of salvage	(13,418)	(10,386)	(4,355)
Construction payables	(49,532)	(50,000)	78,961
Capital grant proceeds	—	4,500	13,372
Proceeds from asset sales	—	79,020	—
Other investing activities	(19,217)	14,903	(16,706)
Net cash used for investing activities	(1,339,607)	(1,602,745)	(1,548,775)
Financing Activities:			
Proceeds —			
Capital contributions from parent company	451,387	1,077,088	702,971
Bonds — Other	22,866	42,342	51,471
Senior notes issuances	—	—	600,000
Interest-bearing refundable deposit	125,000	—	150,000
Other long-term debt issuances	470,000	475,000	50,000
Redemptions —			
Bonds — Other	(34,116)	(82,563)	—
Capital Leases	(2,539)	(697)	(633)
Senior notes	—	(50,000)	(90,000)
Other long-term debt	(220,000)	(125,000)	(115,000)
Return of paid in capital	(219,720)	(104,804)	—
Payment of preferred stock dividends	(1,733)	(1,733)	(1,733)
Payment of common stock dividends	—	(71,956)	(106,800)
Other financing activities	1,414	(2,343)	6,512
Net cash provided from financing activities	592,559	1,155,334	1,246,788
Net Change in Cash and Cash Equivalents	(12,664)	157	(66,577)
Cash and Cash Equivalents at Beginning of Year	145,165	145,008	211,585
Cash and Cash Equivalents at End of Year	$ 132,501	$ 145,165	$ 145,008
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $68,679, $54,118 and $32,816 capitalized, respectively)	$ 6,992	$ 20,285	$ 32,589
Income taxes (net of refunds)	(379,158)	(134,198)	(77,580)
Noncash transactions —			
Accrued property additions at year-end	114,469	164,863	214,863
Capital lease obligation	—	82,915	—

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

BALANCE SHEETS
At December 31, 2014 and 2013
Mississippi Power Company 2014 Annual Report

Assets	2014	2013
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 132,501	$ 145,165
Receivables —		
Customer accounts receivable	40,648	40,978
Unbilled revenues	35,494	38,895
Under recovered regulatory clause revenues	2,471	—
Other accounts and notes receivable	11,256	4,600
Affiliated companies	51,060	34,920
Accumulated provision for uncollectible accounts	(825)	(3,018)
Fossil fuel stock, at average cost	100,164	113,285
Materials and supplies, at average cost	61,582	45,347
Other regulatory assets, current	72,840	48,583
Prepaid income taxes	190,631	34,751
Other current assets	6,209	9,357
Total current assets	704,031	512,863
Property, Plant, and Equipment:		
In service	4,378,087	3,458,770
Less accumulated provision for depreciation	1,172,715	1,095,352
Plant in service, net of depreciation	3,205,372	2,363,418
Construction work in progress	2,160,646	2,586,031
Total property, plant, and equipment	5,366,018	4,949,449
Other Property and Investments	5,498	4,857
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	225,507	143,747
Other regulatory assets, deferred	385,410	200,620
Accumulated deferred income taxes	17,388	—
Other deferred charges and assets	52,876	36,673
Total deferred charges and other assets	681,181	381,040
Total Assets	$ 6,756,728	$ 5,848,209

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

BALANCE SHEETS
At December 31, 2014 and 2013
Mississippi Power Company 2014 Annual Report

Liabilities and Stockholder's Equity	2014	2013
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 777,667**	$ 13,789
Interest-bearing refundable deposit	**275,000**	150,000
Accounts payable —		
Affiliated	**85,882**	70,299
Other	**177,736**	210,191
Customer deposits	**14,970**	14,379
Accrued taxes —		
Accrued income taxes	**142,461**	5,590
Other accrued taxes	**83,686**	77,958
Accrued interest	**76,494**	47,144
Accrued compensation	**26,331**	9,324
Other regulatory liabilities, current	**2,164**	14,480
Over recovered regulatory clause liabilities	**532**	18,358
Mirror CWIP	**270,779**	—
Other current liabilities	**44,701**	21,413
Total current liabilities	**1,978,403**	652,925
Long-Term Debt (See accompanying statements)	**1,630,487**	2,167,067
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**284,849**	72,808
Deferred credits related to income taxes	**9,370**	10,191
Accumulated deferred investment tax credits	**282,816**	284,248
Employee benefit obligations	**147,536**	94,430
Asset retirement obligations	**48,248**	41,197
Other cost of removal obligations	**165,999**	156,683
Other regulatory liabilities, deferred	**63,681**	144,992
Other deferred credits and liabilities	**28,299**	14,337
Total deferred credits and other liabilities	**1,030,798**	818,886
Total Liabilities	**4,639,688**	3,638,878
Cumulative Redeemable Preferred Stock (See accompanying statements)	**32,780**	32,780
Common Stockholder's Equity (See accompanying statements)	**2,084,260**	2,176,551
Total Liabilities and Stockholder's Equity	**$ 6,756,728**	$ 5,848,209
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2014 and 2013
Mississippi Power Company 2014 Annual Report

	2014	2013	2014	2013
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
2.35% due 2016	**$ 300,000**	$ 300,000		
5.60% due 2017	**35,000**	35,000		
5.55% due 2019	**125,000**	125,000		
1.63% to 5.40% due 2035-2042	**680,000**	680,000		
Adjustable rate (1.29% at 1/1/14) due 2014	**—**	11,250		
Adjustable rates (0.77% to 1.17% at 1/1/15) due 2015	**775,000**	525,000		
Total long-term notes payable	**1,915,000**	1,676,250		
Other long-term debt —				
Pollution control revenue bonds:				
5.15% due 2028	**42,625**	42,625		
Variable rates (0.02% to 0.06% at 1/1/15) due 2020-2028	**40,070**	40,070		
Plant Daniel revenue bonds (7.13%) due 2021	**270,000**	270,000		
Total other long-term debt	**352,695**	352,695		
Capitalized lease obligations	**79,679**	82,217		
Unamortized debt premium	**62,701**	71,807		
Unamortized debt discount	**(1,921)**	(2,113)		
Total long-term debt (annual interest requirement — $78 million)	**2,408,154**	2,180,856		
Less amount due within one year	**777,667**	13,789		
Long-term debt excluding amount due within one year	**1,630,487**	2,167,067	**43.5%**	49.6%
Cumulative Redeemable Preferred Stock:				
$100 par value				
Authorized — 1,244,139 shares				
Outstanding — 334,210 shares				
4.40% to 5.25% (annual dividend requirement — $1.7 million)	**32,780**	32,780	**0.9**	0.7
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 1,130,000 shares				
Outstanding — 1,121,000 shares	**37,691**	37,691		
Paid-in capital	**2,612,136**	2,376,595		
Accumulated deficit	**(558,552)**	(229,871)		
Accumulated other comprehensive loss	**(7,015)**	(7,864)		
Total common stockholder's equity	**2,084,260**	2,176,551	**55.6**	49.7
Total Capitalization	**$ 3,747,527**	$ 4,376,398	**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, 2014, 2013, and 2012
Mississippi Power Company 2014 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)			
Balance at December 31, 2011	1,121	$ 37,691	$ 694,855	$ 325,568	$ (8,897)	$ 1,049,217
Net income after dividends on preferred stock	—	—	—	99,942	—	99,942
Capital contributions from parent company	—	—	706,665	—	—	706,665
Other comprehensive income (loss)	—	—	—	—	184	184
Cash dividends on common stock	—	—	—	(106,800)	—	(106,800)
Balance at December 31, 2012	1,121	37,691	1,401,520	318,710	(8,713)	1,749,208
Net loss after dividends on preferred stock	—	—	—	(476,625)	—	(476,625)
Capital contributions from parent company	—	—	975,075	—	—	975,075
Other comprehensive income (loss)	—	—	—	—	849	849
Cash dividends on common stock	—	—	—	(71,956)	—	(71,956)
Balance at December 31, 2013	**1,121**	**37,691**	**2,376,595**	**(229,871)**	**(7,864)**	**2,176,551**
Net loss after dividends on preferred stock	—	—	—	**(328,681)**	—	**(328,681)**
Capital contributions from parent company	—	—	**235,541**	—	—	**235,541**
Other comprehensive income (loss)	—	—	—	—	**849**	**849**
Balance at December 31, 2014	**1,121**	**$ 37,691**	**$2,612,136**	**$ (558,552)**	**$ (7,015)**	**$ 2,084,260**

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

[This page intentionally left blank]

Index to the Notes to Financial Statements

Note		Page
1	Summary of Significant Accounting Polices	II-395
2	Retirement Benefits	II-401
3	Contingencies and Regulatory Matters	II-411
4	Joint Ownership Agreements	II-422
5	Income Taxes	II-422
6	Financing	II-425
7	Commitments	II-428
8	Stock Compensation	II-428
9	Fair Value Measurements	II-429
10	Derivatives	II-431
11	Quarterly Financial Information (Unaudited)	II-436

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Mississippi Power Company (the Company) is a wholly owned subsidiary of The Southern Company (Southern Company), which is the parent company of the Company and three other traditional operating companies, as well as Southern Power, SCS, SouthernLINC Wireless, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, and other direct and indirect subsidiaries. The traditional operating companies – Alabama Power, Georgia Power, Gulf Power, and the Company – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity 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. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants.

The Company is subject to regulation by the FERC and the Mississippi PSC. The Company follows GAAP in the U.S. and complies 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

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

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 $259.0 million, $205.0 million, and $212.7 million during 2014, 2013, and 2012, 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 $13.4 million, $12.5 million, and $11.7 million in 2014, 2013, and 2012, respectively. Also, the Company reimburses Alabama Power for any direct fuel purchases delivered from an Alabama Power transfer facility, which were $34.5 million, $27.1 million, and $28.1 million in 2014, 2013, and 2012, 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 $30.5 million, $16.5 million, and $21.2 million in 2014, 2013, and 2012, respectively. See Note 4 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 herein, the Company neither provided nor received any material services to or from affiliates in 2014 or 2013. The Company received storm assistance from other Southern Company subsidiaries totaling $2.0 million in 2012.

The traditional operating companies, including the Company, and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS, as agent. Each participating company

may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

Regulatory Assets and Liabilities

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

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

	2014	2013	Note
		(in thousands)	
Retiree benefit plans – regulatory assets	$ 169,317	$ 82,799	(a,g)
Property damage	(61,648)	(60,092)	(i)
Deferred income tax charges	222,599	140,185	(c)
Property tax	27,680	31,206	(d)
Vacation pay	11,172	10,214	(e,g)
Loss on reacquired debt	8,542	9,178	(k)
Plant Daniel Units 3 and 4 regulatory assets	23,013	18,821	(j)
Other regulatory assets	16,270	5,415	(b)
Fuel-hedging (realized and unrealized) losses	46,631	10,340	(f,g)
Asset retirement obligations	10,845	8,918	(c)
Deferred income tax credits	(9,370)	(10,191)	(c)
Other cost of removal obligations	(165,999)	(156,683)	(c)
Kemper IGCC regulatory assets	147,689	75,873	(h)
Mirror CWIP / Kemper regulatory deferral	(270,779)	(90,524)	(h)
Other regulatory liabilities	(4,198)	(8,855)	(b)
Total regulatory assets (liabilities), net	$ 171,764	$ 66,604	

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) Recorded and recovered (amortized) as approved by the Mississippi PSC.

(c) Asset retirement and removal assets and liabilities and deferred income tax assets are recovered, and removal assets 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) Recovered through the ad valorem tax adjustment clause over a 12-month period beginning in April of the following year. See Note 3 under "Ad Valorem Tax Adjustment" for additional information.

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

(f) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed four years. Upon final settlement, costs are recovered through the ECM.

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

(h) 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) Deferred and amortized over a 10-year period beginning October 2021, as approved by the Mississippi PSC for the difference between the revenue requirement under the purchase option and the revenue requirement assuming operating lease accounting treatment for the extended term.

(k) Recovered over the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 50 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 any 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 agreement with SCS, agreed to fund $270.0 million of the Kemper IGCC through the DOE Grants funds. Through December 31, 2014, the Company has received grant funds of $245.3 million, 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. 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 represented 21.9% of the Company's total operating revenues in 2014 and are largely subject to rolling 10-year cancellation notices.

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.

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. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of operations.

In accordance with accounting standards related to the uncertainty in income taxes, 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:

	2014	2013
	(in thousands)	
Generation	**$ 2,293,511**	$ 1,475,264
Transmission	**664,618**	633,903
Distribution	**853,835**	828,470
General	**484,711**	439,721
Plant acquisition adjustment	**81,412**	81,412
Total plant in service	**$ 4,378,087**	$ 3,458,770

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, which are charged to fuel stock and recovered through the Company's fuel clause or charged to regulatory assets to be recovered through rates over the life of the assets starting after the Kemper plant is placed in service. In addition, the cost of maintenance, repairs, and replacement of minor items of property for Kemper IGCC assets in service, excluding the lignite mine, are deferred in regulatory assets. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

Depreciation, Depletion, and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 3.3% in 2014, 3.4% in 2013, and 3.5% in 2012. Depreciation studies are conducted periodically to update the composite rates. 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.

In January 2012, the Mississippi PSC issued an order allowing the Company to defer in a regulatory asset the difference between the revenue requirement under the purchase option of Plant Daniel Units 3 and 4 and the revenue requirement assuming operating lease accounting treatment for the extended term. The regulatory asset will be deferred for a 10-year period ending October 2021. At the conclusion of the deferral period, the unamortized deferral balance will be amortized into rates over the remaining life of the units.

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. Depreciation associated with in-service Kemper IGCC-related assets has been deferred as a regulatory asset to be recovered over the life of the Kemper IGCC.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) are computed as the present value of the 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. 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 Company has AROs 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, 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 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 the 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 either a regulatory asset or liability, as ordered by the Mississippi PSC, and are reflected in the balance sheets.

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

	2014	2013
	(in thousands)	
Balance at beginning of year	$ 41,910	$ 42,115
Liabilities settled	(2,529)	(24)
Accretion	1,969	1,840
Cash flow revisions	6,898	(2,021)
Balance at end of year	$ 48,248	$ 41,910

The increase in cash flow revisions in 2014 related to the Company's AROs associated with Watson landfill and Greene County asbestos.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in landfills and surface impoundments at active generating power plants. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $64 million and ongoing post-closure care of approximately $12 million. The Company will record AROs for the estimated closure costs required under the CCR Rule during 2015. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in the calculation of taxable income. The average annual AFUDC rate was 6.91%, 6.89%, and 7.04% for the years ended December 31, 2014, 2013, and 2012, respectively. AFUDC equity was $136.4 million, $121.6 million, and $64.8 million in 2014, 2013, and 2012, 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 exceed $50,000 is charged to the reserve. Every three years the Mississippi PSC, 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. 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. In 2014, 2013, and 2012, the Company made retail accruals of $3.3 million, $3.2 million, and $3.5 million, respectively. The Company accrued $0.3 million annually in 2014, 2013, and 2012 for the wholesale jurisdiction. As of December 31, 2014, the property damage reserve balances were $60.7 million and $1.0 million for retail and wholesale, 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 appropriate, 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 is charged 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 incurred, 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 (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 are recorded in CWIP. Any ineffectiveness arising from these would be recognized currently in net income; however, the Company has regulatory approval allowing it to defer any ineffectiveness arising from hedging instruments relating to the Kemper IGCC to a regulatory asset. 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. The amounts related to derivatives on the cash flow statement are classified in the same category as the items being hedged. See Note 10 for additional information regarding derivatives.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company has no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2014.

The Company has an ECM clause which, among other things, allows the Company to utilize financial instruments to hedge its fuel commitments. Changes in the fair value of these financial instruments are recorded as regulatory assets or liabilities. Amounts paid or received as a result of financial settlement of these instruments are classified as fuel expense and are included in the ECM factor applied to customer billings. The Company's jurisdictional wholesale customers have a similar ECM mechanism, which has been approved by the FERC.

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

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, certain changes in pension and other postretirement benefit plans, 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 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. For the year ended December 31, 2014, the VIE consolidation resulted in an ARO asset and associated liability in the amounts of $21.0 million and $23.6 million, respectively. For the year ended December 31, 2013, the VIE consolidation resulted in an ARO and an associated liability in the amounts of $21.0 million and $22.7 million, respectively. For the year ended December 31, 2012, the VIE consolidation resulted in an ARO and associated liability in the amounts of $21.0 million and $21.8 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). In December 2014, the Company voluntarily contributed $33 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. 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, 2015, no other postretirement trust contributions are expected.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2011 for the 2012 plan year using discount rates for the pension plans and the other postretirement benefit plans of 4.98% and 4.87%, respectively, and an annual salary increase of 3.84%.

	2014	2013	2012
Discount rate:			
Pension plans	**4.17%**	5.01%	4.26%
Other postretirement benefit plans	**4.03**	4.85	4.04
Annual salary increase	**3.59**	3.59	3.59
Long-term return on plan assets:			
Pension plans	**8.20**	8.20	8.20
Other postretirement benefit plans	**7.30**	7.04	6.96

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

For purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $30.2 million and $5.2 million, respectively.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2014 were as follows:

	Initial Cost Trend Rate	**Ultimate Cost Trend Rate**	**Year That Ultimate Rate is Reached**
Pre-65	9.00%	4.50%	2024
Post-65 medical	6.00	4.50	2024
Post-65 prescription	6.75	4.50	2024

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, 2014 as follows:

	1 Percent Increase	**1 Percent Decrease**
	(in thousands)	
Benefit obligation	$ 6,241	$ (5,289)
Service and interest costs	250	(212)

Pension Plans

The total accumulated benefit obligation for the pension plans was $462 million at December 31, 2014 and $370 million at December 31, 2013. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 409,395	$ 432,553
Service cost	10,123	11,067
Interest cost	20,093	18,062
Benefits paid	(17,499)	(16,207)
Actuarial (gain) loss	90,735	(36,080)
Balance at end of year	512,847	409,395
Change in plan assets		
Fair value of plan assets at beginning of year	387,403	351,749
Actual return on plan assets	40,051	49,431
Employer contributions	35,526	2,430
Benefits paid	(17,499)	(16,207)
Fair value of plan assets at end of year	445,481	387,403
Accrued liability	$ (67,366)	$ (21,992)

At December 31, 2014, the projected benefit obligations for the qualified and non-qualified pension plans were $481 million and $32 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's pension plans consist of the following:

	2014	2013
	(in thousands)	
Prepaid pension costs	$ —	$ 5,698
Other regulatory assets, deferred	150,972	77,572
Other current liabilities	(2,337)	(2,134)
Employee benefit obligations	(65,029)	(25,556)

Presented below are the amounts included in regulatory assets at December 31, 2014 and 2013 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 2015.

	2014	2013	Estimated Amortization in 2015
		(in thousands)	
Prior service cost	$ 3,030	$ 4,118	$ 1,088
Net (gain) loss	147,942	73,454	10,293
Regulatory assets	$ 150,972	$ 77,572	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in thousands)	
Regulatory assets:		
Beginning balance	**$ 77,572**	$ 146,838
Net (gain) loss	**79,425**	(58,662)
Reclassification adjustments:		
Amortization of prior service costs	**(1,088)**	(1,143)
Amortization of net gain (loss)	**(4,937)**	(9,461)
Total reclassification adjustments	**(6,025)**	(10,604)
Total change	**73,400**	(69,266)
Ending balance	**$ 150,972**	$ 77,572

Components of net periodic pension cost were as follows:

	2014	2013	2012
		(in thousands)	
Service cost	**$ 10,123**	$ 11,067	$ 9,416
Interest cost	**20,093**	18,062	18,019
Expected return on plan assets	**(28,742)**	(26,849)	(24,121)
Recognized net (gain) loss	**4,937**	9,461	4,100
Net amortization	**1,088**	1,143	1,309
Net periodic pension cost	**$ 7,499**	$ 12,884	$ 8,723

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, 2014, estimated benefit payments were as follows:

	Benefit Payments
	(in thousands)
2015	$ 23,304
2016	19,551
2017	20,816
2018	21,905
2019	23,337
2020 to 2024	135,320

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 80,940	$ 91,783
Service cost	1,025	1,151
Interest cost	3,812	3,619
Benefits paid	(4,887)	(4,080)
Actuarial (gain) loss	14,259	(11,959)
Retiree drug subsidy	506	426
Balance at end of year	95,655	80,940
Change in plan assets		
Fair value of plan assets at beginning of year	23,277	21,990
Actual return on plan assets	1,814	2,379
Employer contributions	3,413	2,562
Benefits paid	(4,381)	(3,654)
Fair value of plan assets at end of year	24,123	23,277
Accrued liability	$ (71,532)	$ (57,663)

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's other postretirement benefit plans consist of the following:

	2014	2013
	(in thousands)	
Other regulatory assets, deferred	$ 18,345	$ 5,227
Other regulatory liabilities, deferred	(2,011)	(3,111)
Employee benefit obligations	(71,532)	(57,663)

Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2014 and 2013 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 2015.

	2014	2013	Estimated Amortization in 2015
		(in thousands)	
Prior service cost	$ (2,123)	$ (2,311)	$ (188)
Net (gain) loss	18,457	4,427	778
Net regulatory assets	$ 16,334	$ 2,116	

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in thousands)	
Net regulatory assets (liabilities):		
Beginning balance	**$ 2,116**	$ 15,454
Net (gain) loss	**14,030**	(12,867)
Reclassification adjustments:		
Amortization of prior service costs	**188**	188
Amortization of net gain (loss)	**—**	(659)
Total reclassification adjustments	**188**	(471)
Total change	**14,218**	(13,338)
Ending balance	**$ 16,334**	$ 2,116

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

	2014	2013	2012
		(in thousands)	
Service cost	**$ 1,025**	$ 1,151	$ 1,038
Interest cost	**3,812**	3,619	4,155
Expected return on plan assets	**(1,585)**	(1,472)	(1,552)
Net amortization	**(188)**	471	470
Net periodic postretirement benefit cost	**$ 3,064**	$ 3,769	$ 4,111

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 thousands)	
2015	$ 5,387	$ (512)	$ 4,875
2016	5,632	(566)	5,066
2017	5,911	(622)	5,289
2018	6,185	(680)	5,505
2019	6,475	(735)	5,740
2020 to 2024	34,139	(3,744)	30,395

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.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2014 and 2013, along with the targeted mix of assets for each plan, is presented below:

	Target	2014	2013
Pension plan assets:			
Domestic equity	26%	30%	31%
International equity	25	23	25
Fixed income	23	27	23
Special situations	3	1	1
Real estate investments	14	14	14
Private equity	9	5	6
Total	100%	100%	100%
Other postretirement benefit plan assets:			
Domestic equity	21%	24%	25%
International equity	21	19	20
Domestic fixed income	37	41	38
Special situations	3	1	1
Real estate investments	11	11	11
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, 2014 and 2013. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management

relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

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

- ***Domestic and international equity.*** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- ***Fixed income.*** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- ***Real estate investments and private equity.*** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

The fair values of pension plan assets as of December 31, 2014 and 2013 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2014:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Domestic equity*	$ 78,344	$ 32,366	$ —	$ 110,710
International equity*	49,170	45,313	—	94,483
Fixed income:				
U.S. Treasury, government, and agency bonds	—	32,145	—	32,145
Mortgage- and asset-backed securities	—	8,646	—	8,646
Corporate bonds	—	52,185	—	52,185
Pooled funds	—	23,632	—	23,632
Cash equivalents and other	133	30,327	—	30,460
Real estate investments	13,479	—	51,520	64,999
Private equity	—	—	26,203	26,203
Total	$ 141,126	$ 224,614	$ 77,723	$ 443,463
Liabilities:				
Derivatives	$ (89)	$ —	$ —	$ (89)
Total	$ 141,037	$ 224,614	$ 77,723	$ 443,374

* 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, 2013:	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)	Total
		(in thousands)		
Assets:				
Domestic equity*	$ 63,558	$ 37,206	$ —	$ 100,764
International equity*	48,829	45,146	—	93,975
Fixed income:				
U.S. Treasury, government, and agency bonds	—	26,582	—	26,582
Mortgage- and asset-backed securities	—	6,904	—	6,904
Corporate bonds	—	43,420	—	43,420
Pooled funds	—	20,905	—	20,905
Cash equivalents and other	38	9,896	—	9,934
Real estate investments	11,546	—	44,341	55,887
Private equity	—	—	25,316	25,316
Total	$ 123,971	$ 190,059	$ 69,657	$ 383,687
Liabilities:				
Derivatives	$ —	$ (115)	$ —	$ (115)
Total	$ 123,971	$ 189,944	$ 69,657	$ 383,572

* 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.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2014 and 2013 were as follows:

	2014		2013	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in thousands)		
Beginning balance	$ 44,341	$ 25,316	$ 37,196	$ 26,240
Actual return on investments:				
Related to investments held at year end	5,253	3,269	3,385	378
Related to investments sold during the year	1,525	(745)	1,316	2,300
Total return on investments	6,778	2,524	4,701	2,678
Purchases, sales, and settlements	401	(1,637)	2,444	(3,602)
Ending balance	$ 51,520	$ 26,203	$ 44,341	$ 25,316

The fair values of other postretirement benefit plan assets as of December 31, 2014 and 2013 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Domestic equity*	$ 3,450	$ 1,425	$ —	$ 4,875
International equity*	2,165	1,997	—	4,162
Fixed income:				
U.S. Treasury, government, and agency bonds	—	5,279	—	5,279
Mortgage- and asset-backed securities	—	380	—	380
Corporate bonds	—	2,301	—	2,301
Pooled funds	—	1,041	—	1,041
Cash equivalents and other	589	1,337	—	1,926
Real estate investments	593	—	2,269	2,862
Private equity	—	—	1,154	1,154
Total	$ 6,797	$ 13,760	$ 3,423	$ 23,980
Liabilities:				
Derivatives	$ (5)	$ —	$ —	$ (5)
Total	$ 6,792	$ 13,760	$ 3,423	$ 23,975

* 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, 2013:	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)	Total
		(in thousands)		
Assets:				
Domestic equity*	$ 3,089	$ 1,809	$ —	$ 4,898
International equity*	2,375	2,193	—	4,568
Fixed income:				
U.S. Treasury, government, and agency bonds	—	5,213	—	5,213
Mortgage- and asset-backed securities	—	337	—	337
Corporate bonds	—	2,109	—	2,109
Pooled funds	—	1,016	—	1,016
Cash equivalents and other	1	968	—	969
Real estate investments	560	—	2,156	2,716
Private equity	—	—	1,231	1,231
Total	$ 6,025	$ 13,645	$ 3,387	$ 23,057
Liabilities:				
Derivatives	$ —	$ (5)	$ —	$ (5)
Total	$ 6,025	$ 13,640	$ 3,387	$ 23,052

* 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.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2014 and 2013 were as follows:

	2014		2013	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in thousands)		
Beginning balance	**$ 2,156**	**$ 1,231**	$ 1,865	$ 1,293
Actual return on investments:				
Related to investments held at year end	**28**	**28**	158	18
Related to investments sold during the year	**67**	**(33)**	64	110
Total return on investments	**95**	**(5)**	222	128
Purchases, sales, and settlements	**18**	**(72)**	69	(190)
Ending balance	**$ 2,269**	**$ 1,154**	$ 2,156	$ 1,231

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 2014, 2013, and 2012 were $4.6 million, $4.1 million, and $3.9 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

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against Alabama Power alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by the Company. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. These actions were filed concurrently with the issuance of notices of violation to the Company with respect to the Company's Plant Watson. The case against Alabama Power (including claims involving a unit co-owned by the Company) has been actively litigated in the U.S. District Court for the Northern District of Alabama, resulting in a settlement in 2006 of the alleged NSR violations at Plant Miller; voluntary dismissal of certain claims by the EPA; and a grant of summary judgment for Alabama Power on all remaining claims and dismissal of the case with prejudice in 2011. In September 2013, the U.S. Court of Appeals for the Eleventh Circuit affirmed in part and reversed in part the 2011 judgment in favor of Alabama Power, and the case has been transferred back to the U.S. District Court for the Northern District of Alabama for further proceedings.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

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 properties. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through regulatory mechanisms.

In 2003, the Company and numerous other entities were designated by the Texas Commission on Environmental Quality (TCEQ) as potentially responsible parties at a site that was owned by an electric transformer company that handled the Company's transformers. The TCEQ approved the final site remediation plan in December 2013 and, on March 28, 2014, the impacted utilities, including the Company, agreed to commence remediation actions on the site. The Company's environmental remediation liability is $0.5 million as of December 31, 2014 and is expected to be recovered through the ECO Plan.

The final outcome of this matter cannot now be determined. However, based on the currently known conditions at this site and the nature and extent of activities relating to this site, the Company does not believe that additional liabilities, if any, at this site would be material to the financial statements.

FERC Matters

In 2012, the Company entered into a settlement agreement with its wholesale customers with respect to the Company's request for revised rates under the wholesale cost-based electric tariff. The settlement agreement provided that base rates under the cost-based electric tariff increase by approximately $22.6 million over a 12-month period with revised rates effective April 1, 2012. A significant portion of the difference between the requested base rate increase and the agreed upon rate increase was due to a change in the recovery methodology for the return on the Kemper IGCC CWIP. Under the settlement agreement, a portion of CWIP will continue to accrue AFUDC. The tariff customers specifically agreed to the same regulatory treatment for tariff ratemaking as the treatment approved for retail ratemaking by the Mississippi PSC with respect to (i) the accounting for Kemper IGCC-related costs that cannot be capitalized, (ii) the accounting for the lease termination and purchase of Plant Daniel Units 3 and 4, and (iii) the establishment of a regulatory asset for certain potential plant retirement costs.

Also in 2012, the FERC approved a motion to place interim rates into effect beginning in May 2012. Later in 2012, the Company, with its wholesale customers, filed a final settlement agreement with the FERC. In May 2013, the Company received an order from the FERC accepting the settlement agreement.

In April 2013, the Company reached a settlement agreement with its wholesale customers and filed a request with the FERC for an additional increase in the MRA cost-based electric tariff, which was accepted by the FERC in May 2013. The 2013 settlement agreement provided that base rates under the MRA cost-based electric tariff will increase by approximately $24.2 million annually, effective April 1, 2013.

On March 31, 2014, the Company reached a settlement agreement with its wholesale customers and filed a request with the FERC for an increase in the MRA cost-based electric tariff. The settlement agreement, accepted by the FERC on May 20, 2014, provides that base rates under the MRA cost-based electric tariff will increase approximately $10.1 million annually, with revised rates effective for services rendered beginning May 1, 2014.

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 March 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.

Energy Efficiency

In July 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. An annual report addressing the performance of all energy efficiency programs is required.

On June 3, 2014, the Mississippi PSC approved the Company's 2014 Energy Efficiency Quick Start Plan filing, which includes a portfolio of energy efficiency programs. On October 20, 2014, the Company filed a revised compliance filing, which proposed an increase of $6.7 million in retail revenues for the period December 2014 through December 2015. The Mississippi PSC approved the revised filing on November 4, 2014.

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 projected revenue requirement, and the PEP lookback filing, which is filed after the year and allows for review of the actual revenue requirement compared to the projected filing. PEP was designed with the objective to reduce the impact of rate changes on the customer and provide incentives for the Company to keep customer prices low and customer satisfaction and reliability high. PEP is a mechanism for rate adjustments based on three indicators: price, customer satisfaction, and service reliability.

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 May 2013, the MPUS contested the Company's PEP lookback filing for 2012, which indicated a refund due to customers of $4.7 million. Unresolved matters related to certain costs included in the 2010 PEP lookback filing, which are currently under review, also impact the 2012 PEP lookback filing.

In March 2013, the Mississippi PSC approved the projected PEP filing for 2013, which resulted in a rate increase of 1.9%, or $15.3 million, annually, effective March 19, 2013. The Company may be entitled to $3.3 million in additional revenues related to 2013 as a result of the late implementation of the 2013 PEP rate increase.

On March 18, 2014, the Company submitted its annual PEP lookback filing for 2013, which indicated no surcharge or refund. On March 31, 2014, the Mississippi PSC suspended the filing to allow more time for review.

On June 3, 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.

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 are scheduled to be placed in service in September and November 2015, respectively. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. The estimated total cost of the project is approximately $660 million, with the Company's portion being $330 million, excluding AFUDC. The Company's portion of the cost is expected to be recovered through the ECO Plan following the scheduled completion of the project. As of December 31, 2014, total project expenditures were $518.2 million, of which the Company's portion was $263.4 million, excluding AFUDC of $19.2 million.

In August 2013, the Mississippi PSC approved the Company's 2013 ECO Plan filing which proposed no change in rates.

On August 1, 2014, the Company entered into a settlement agreement with the Sierra Club (Sierra Club Settlement Agreement) that, among other things, requires 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. 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. 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, and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) and begin operating those units solely on natural gas no later than April 2016. On August 28, 2014, the Chancery Court of Harrison County, Mississippi dismissed the Sierra Club's appeal related to the CPCN to construct scrubbers on Plant Daniel Units 1 and 2.

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. This request was made to minimize the potential rate impact to customers arising from pending and final environmental regulations which may require the premature retirement of some generating units. As of December 31, 2014, $5.6 million of Plant Greene County costs and $2.0 million of costs related to Plant Watson have been reclassified as a regulatory asset. These costs are expected to be recovered through the ECO plan and other existing cost recovery mechanisms. Additional costs associated with the remaining net book value of coal-related equipment will be reclassified to a regulatory asset at the time of retirement for Plants Watson and Greene County in 2015 and 2016, respectively. Approved regulatory asset costs will be amortized over a period to be determined by the Mississippi PSC. As a result, these decisions are not expected to have a material impact on the Company's financial statements. See "Other Matters – Sierra Club Settlement Agreement" herein for additional information.

The ultimate outcome of these matters 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 most recent filing occurred on November 17, 2014. On January 13, 2015, the Mississippi PSC approved the 2015 retail fuel cost recovery factor, effective January 21, 2015. The retail fuel cost recovery factor will result in an annual increase of approximately $7.9 million. At December 31, 2014, the amount of under-recovered retail fuel costs included in the balance sheets was $2.5 million compared to a $14.5 million over-recovered balance at December 31, 2013.

The Company also has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2015, the wholesale MRA fuel rate decreased resulting in an annual decrease of $1.1 million. Effective February 1, 2015, the wholesale MB fuel rate decreased, resulting in an annual decrease of $0.1 million. At December 31, 2014, the amount of over-recovered wholesale MRA fuel costs included in the balance sheets was $0.2 million compared to an over-recovered balance of $7.3 million at December 31, 2013. At December 31, 2014, the amount of over-recovered wholesale MB fuel costs included in the balance sheets was immaterial compared to an over-recovered balance of $0.3 million at December 31, 2013. In addition, at December 31, 2014, the amount of over-recovered MRA emissions allowance cost included in the balance sheets was $0.3 million compared to a $3.8 million under-recovered balance at December 31, 2013. 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 May 6, 2014, the Mississippi PSC approved the Company's annual ad valorem tax adjustment factor filing for 2014, in which the Company requested an annual rate increase of 0.38%, or $3.6 million in annual retail revenues, primarily due to an increase in property tax rates.

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. In the 2015 Mississippi Supreme Court (Court) decision, the Court declined to rule on the constitutionality of the Baseload Act. See "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" and " – 2015 Mississippi Supreme Court Decision" herein for additional information.

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

Construction of the Kemper IGCC is nearing completion and start-up activities will continue until the Kemper IGCC is placed in service. The Kemper IGCC will utilize an IGCC technology with an output capacity of 582 MWs. 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. In connection with the Kemper IGCC, the Company constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the planned 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 $245.3 million of 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 on natural gas on August 9, 2014 and continues to focus on completing the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, for which the in-service date is currently expected to occur in the first half of 2016.

Recovery of the Kemper IGCC 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) and costs subject to the cost cap remain subject to review and approval by the Mississippi PSC. The Company's Kemper IGCC 2010 project estimate, current cost estimate (which includes the impacts of the Court's decision), and actual costs incurred as of December 31, 2014, as adjusted for the Court's decision, are as follows:

Cost Category	2010 Project Estimate[f]	Current Estimate	**Actual Costs at 12/31/2014**
		(in billions)	
Plant Subject to Cost Cap[a]	$ 2.40	$ 4.93	**$ 4.23**
Lignite Mine and Equipment	0.21	0.23	**0.23**
CO_2 Pipeline Facilities	0.14	0.11	**0.10**
AFUDC[b][c]	0.17	0.63	**0.45**
Combined Cycle and Related Assets Placed in Service – Incremental[d]	—	0.02	0.00
General Exceptions	0.05	0.10	**0.07**
Deferred Costs[c][e]	—	0.18	**0.12**
Total Kemper IGCC[a][c]	$ 2.97	$ 6.20	**$ 5.20**

(a) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, net of the DOE Grants and excluding the Cost Cap Exceptions. The Current Estimate and Actual Costs include non-incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service on August 9, 2014 that are subject to the $2.88 billion cost cap and excludes post-in-service costs for the lignite mine. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" for additional information.

(b) The Company's original estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC in 2012 as described in "Rate Recovery of Kemper IGCC Costs."

(c) Amounts in the Current Estimate reflect estimated costs through March 31, 2016.

(d) Incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service on August 9, 2014, net of costs related to energy sales. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" for additional information.

(e) The 2012 MPSC CPCN Order approved deferral of non-capital Kemper IGCC-related costs during construction as described in "Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities."

(f) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities which was approved in 2011 by the Mississippi PSC.

Of the total costs, including post-in-service costs for the lignite mine, incurred as of December 31, 2014, $3.04 billion was included in property, plant, and equipment (which is net of the DOE Grants and estimated probable losses of $2.05 billion), $1.8 million in other property and investments, $44.7 million in fossil fuel stock, $32.5 million in materials and supplies, $147.7 million in other regulatory assets, $11.6 million in other deferred charges and assets, and $23.6 million in AROs in the balance sheet, with $1.1 million previously expensed.

The Company does not intend to seek any rate recovery or joint owner contributions for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. The Company recorded pre-tax charges to income for revisions to the cost estimate of $868.0 million ($536.0 million after tax), $1.10 billion ($680.5 million after tax), and $78.0 million ($48.2 million after tax) in 2014, 2013 and 2012, respectively. The increases to the cost estimate in 2014 primarily reflected costs related to extension of the project's schedule to ensure the required time for start-up activities and operational readiness, completion of construction, additional resources during start-up, and ongoing construction support during start-up and commissioning activities. The current estimate includes costs through March 31, 2016. Any further extension of the in-service date is currently estimated to result in additional base costs of approximately $25 million to $30 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. Any further extension of the in-service date with respect to the Kemper IGCC 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 $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees, which are being deferred as regulatory assets and are estimated to total approximately $7 million per month.

Any further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (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). In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the Company's statements of operations and these changes could be material.

Rate Recovery of Kemper IGCC Costs

See "FERC Matters" for additional information regarding the Company's MRA cost-based tariff relating to recovery of a portion of the Kemper IGCC costs from the Company's wholesale customers. Rate recovery of the retail portion of the Kemper IGCC is subject to the jurisdiction of the Mississippi PSC. See Note 3 under "Retail Regulatory Matters – Baseload Act" for additional information. See "Investment Tax Credits and Bonus Depreciation" and "Section 174 Research and Experimental Deduction" herein for additional tax information related to the Kemper IGCC.

The ultimate outcome of the rate recovery matters discussed herein, including the resolution of legal challenges, determinations of prudency, and the specific manner of recovery of prudently-incurred costs, cannot be determined at this time, but could have a material impact on the Company's results of operations, financial condition, and liquidity.

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 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 evaluation of the Rate Mitigation Plan (defined below) and other related proceedings during 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.

2013 Settlement Agreement

In January 2013, the Company entered into a settlement agreement with the Mississippi PSC that, among other things, established 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. The 2013 Settlement Agreement also allowed the Company to secure alternate financing for costs not otherwise recovered in any Mississippi PSC rate proceedings contemplated by the 2013 Settlement Agreement. The Court found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. See "2015 Mississippi Supreme Court Decision" below for additional information.

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 February 2013. The Company's intent under the 2013 Settlement Agreement was to securitize (1) prudently-incurred costs in excess of the certificated cost estimate and up to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, (2) accrued AFUDC, and (3) other prudently-incurred costs, which include carrying costs from the estimated in-service date until securitization is finalized and other costs not included in the Rate Mitigation Plan as approved by the Mississippi PSC.

The Court's decision did not impact the Company's ability to utilize alternate financing through securitization, the 2012 MPSC CPCN Order, or the February 2013 legislation. See "2015 Mississippi Supreme Court Decision" below for additional information.

2013 MPSC Rate Order

Consistent with the terms of the 2013 Settlement Agreement, in March 2013, the Mississippi PSC issued the 2013 MPSC 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. For the period from March 2013 through December 31, 2014,

$257.2 million had been collected primarily to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service.

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 the in-service date. The Company will not record AFUDC on any additional costs of the Kemper IGCC that exceed the $2.88 billion cost cap, except for Cost Cap Exception amounts. The Company will continue to record AFUDC and collect and defer the approved rates through the in-service date until directed to do otherwise by the Mississippi PSC.

On August 18, 2014, the Company provided an analysis of the costs and benefits of placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service, including the expected accounting treatment. The Company's analysis requested, among other things, confirmation of the Company's accounting treatment by the Mississippi PSC of the continued collection of rates as prescribed by the 2013 MPSC Rate Order, with the current recognition as revenue of the related equity return on all assets placed in service and the deferral of all remaining rate collections under the 2013 MPSC Rate Order to a regulatory liability account. See "2015 Mississippi Supreme Court Decision" for additional information regarding the decision of the Court which would discontinue the collection of, and require the refund of, all amounts previously collected under the 2013 MPSC Rate Order.

In addition, the Company's August 18, 2014 filing with the Mississippi PSC requested confirmation of the Company's accounting treatment by the Mississippi PSC of the continued accrual of AFUDC through the in-service date of the remainder of the Kemper IGCC and the deferral of operating costs for the combined cycle as regulatory assets. Under the Company's proposal, non-incremental costs that would have been incurred whether or not the combined cycle was placed in service would be included in a regulatory asset and would continue to be subject to the $2.88 billion cost cap. Additionally, incremental costs that would not have been incurred if the combined cycle had not gone into service would be included in a regulatory asset and would not be subject to the cost cap because these costs are incurred to support operation of the combined cycle. All energy revenues associated with the combined cycle variable operating and maintenance expenses would be credited to this regulatory asset. See "Regulatory Assets and Liabilities" for additional information. Any action by the Mississippi PSC that is inconsistent with the treatment requested by the Company could have a material impact on the results of operations, financial condition, and liquidity of the Company.

2015 Mississippi Supreme Court Decision

On February 12, 2015, the Court issued its decision in the legal challenge to the 2013 MPSC Rate Order filed by Thomas A. Blanton. 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. The Court's ruling remands the matter to the Mississippi PSC to (1) fix by order the rates that were in existence prior to the 2013 MPSC Rate Order, (2) fix no rate increases until the Mississippi PSC is in compliance with the Court's ruling, and (3) enter an order refunding amounts collected under the 2013 MPSC Rate Order. Through December 31, 2014, the Company had collected $257.2 million through rates under the 2013 MPSC Rate Order. Any required refunds would also include carrying costs. The Court's decision will become legally effective upon the issuance of a mandate to the Mississippi PSC. Absent specific instruction from the Court, the Mississippi PSC will determine the method and timing of the refund. The Company is reviewing the Court's decision and expects to file a motion for rehearing which would stay the Court's mandate until either the case is reheard and decided or seven days after the Court issues its order denying the Company's request for rehearing. The Company is also evaluating its regulatory options.

Rate Mitigation Plan

In March 2013, the Company, in compliance with the 2013 MPSC Rate Order, filed a revision to the proposed rate recovery plan with the Mississippi PSC for the Kemper IGCC for cost recovery through 2020 (Rate Mitigation Plan), which is still under review by the Mississippi PSC. The revenue requirements set forth in the Rate Mitigation Plan assume the sale of a 15% undivided interest in the Kemper IGCC to SMEPA and utilization of bonus depreciation, which currently requires that the related long-term asset be placed in service in 2015. In the Rate Mitigation Plan, the Company proposed recovery of an annual revenue requirement of approximately $156 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. The 2013 MPSC Rate Order, which increased rates beginning in March 2013, was integral to the Rate Mitigation Plan, which contemplates amortization of the regulatory liability balance at the in-service date to be used to mitigate customer rate impacts through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the Rate Mitigation Plan, the Company proposed annual rate recovery to remain the same from 2014

through 2020, with the proposed revenue requirement approximating the forecasted cost of service for the period 2014 through 2020. Under the Company's proposal, to the extent the actual annual cost of service differs from the approved forecast for certain items, the difference would be deferred as a regulatory asset or liability, subject to accrual of carrying costs, and would be included in the next year's rate recovery calculation. If any deferred balance remains at the end of 2020, the Mississippi PSC would review the amount and, if approved, determine the appropriate method and period of disposition. See "Regulatory Assets and Liabilities" and "Investment Tax Credits and Bonus Depreciation" for additional information.

To the extent that refunds of amounts collected under the 2013 MPSC Rate Order are required on a schedule different from the amortization schedule proposed in the Rate Mitigation Plan, the customer billing impacts proposed under the Rate Mitigation Plan would no longer be viable. See "2015 Mississippi Supreme Court Decision" above for additional information.

In the event that the Mirror CWIP regulatory liability is refunded to customers prior to the in-service date of the Kemper IGCC and is, therefore, not available to mitigate rate impacts under the Rate Mitigation Plan, the Mississippi PSC does not approve a refund schedule that facilitates rate mitigation, or the Company withdraws the Rate Mitigation Plan, the Company would seek rate recovery through alternate means, which could include a traditional rate case.

In addition to current estimated costs at December 31, 2014 of $6.20 billion, the Company anticipates that it will incur additional costs after the Kemper IGCC in-service date until the Kemper IGCC cost recovery approach is finalized. These costs include, but are not limited to, regulatory costs and additional carrying costs which could be material. Recovery of these costs would be subject to approval by the Mississippi PSC.

Prudence Reviews

The Mississippi PSC's review of Kemper IGCC costs is ongoing. On August 5, 2014, the Mississippi PSC ordered that a consolidated prudence determination of all Kemper IGCC costs be completed after the entire project has been placed in service and has demonstrated availability for a reasonable period of time as determined by the Mississippi PSC and the MPUS. The Mississippi PSC has encouraged the parties to work in good faith to settle contested issues and the Company is working to reach a mutually acceptable resolution. As a result of the Court's decision, the Company intends to request that the Mississippi PSC reconsider its prudence review schedule. See "2015 Mississippi Supreme Court Decision" 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.

On August 18, 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. As of December 31, 2014, the regulatory asset balance associated with the Kemper IGCC was $147.7 million. The projected balance at March 31, 2016 is estimated to total approximately $269.8 million. The amortization period of 40 years proposed by the Company for any such costs approved for recovery remains subject to approval by the Mississippi PSC.

The 2013 MPSC Rate Order approved 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. On February 12, 2015, the Court ordered the Mississippi PSC to refund Mirror CWIP and to fix by order the rates that were in existence prior to the 2013 MPSC Rate Order. The Company is deferring the collections under the approved rates in the Mirror CWIP regulatory liability until otherwise directed by the Mississippi PSC. The Company is also accruing carrying costs on the unamortized balance of the Mirror CWIP regulatory liability for the benefit of retail customers. As of December 31, 2014, the balance of the Mirror CWIP regulatory liability, including carrying costs, was $270.8 million.

See "2015 Mississippi Supreme Court Decision" for additional information.

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 will own 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 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 has entered into agreements with Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tengrys, LLC, pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC. The agreements with Denbury and Treetop provide termination rights in the event that the Company does not satisfy its contractual obligation with respect to deliveries of captured CO_2 by May 11, 2015. While the Company has received no indication from either Denbury or Treetop of their intent to terminate their respective agreements, any termination could result in a material reduction in future chemical product sales revenues and could have a material financial impact on the Company to the extent the Company is not able to enter into other similar contractual arrangements.

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

Proposed Sale of Undivided Interest to SMEPA

In 2010, the Company and SMEPA entered into an APA whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. In 2012, the Mississippi PSC approved the sale and transfer of the 17.5% undivided interest in the Kemper IGCC to SMEPA. Later in 2012, the Company and SMEPA signed an amendment to the APA whereby SMEPA reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC. In March 2013, the Company and SMEPA signed an amendment to the APA whereby the Company and SMEPA agreed to amend the power supply agreement entered into by the parties in 2011 to reduce the capacity amounts to be received by SMEPA by half (approximately 75 MWs) at the sale and transfer of the undivided interest in the Kemper IGCC to SMEPA. Capacity revenues under the 2011 power supply agreement were $16.7 million in 2014. In December 2013, the Company and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2014.

By letter agreement dated October 6, 2014, the Company and SMEPA agreed in principle on certain issues related to SMEPA's proposed purchase of a 15% undivided interest in the Kemper IGCC. The letter agreement contemplated certain amendments to the APA, which the parties anticipated to be incorporated into the APA on or before December 31, 2014. The parties agreed to further amend the APA as follows: (1) the Company agreed to cap at $2.88 billion the portion of the purchase price payable for development and construction costs, net of the Cost Cap Exceptions, title insurance reimbursement, and AFUDC and/or carrying costs through the Closing Commitment Date (defined below); (2) SMEPA agreed to close the purchase within 180 days after the date of the execution of the amended APA or before the Kemper IGCC in-service date, whichever occurs first (Closing Commitment Date), subject only to satisfaction of certain conditions; and (3) AFUDC and/or carrying costs will continue to be accrued on the capped development and construction costs, the Cost Cap Exceptions, and any operating costs, net of revenues until the amended APA is executed by both parties, and thereafter AFUDC and/or carrying costs and payment of interest on SMEPA's deposited money will be suspended and waived provided closing occurs by the Closing Commitment Date. The letter agreement also provided for certain post-closing adjustments to address any differences between the actual and the estimated amounts of post-in-service date costs (both expenses and capital) and revenue credits for those portions of the Kemper IGCC previously placed in service.

By letter dated December 18, 2014, SMEPA notified the Company that SMEPA decided not to extend the estimated closing date in the APA or revise the APA to include the contemplated amendments; however, both parties agree that the APA will remain in effect until closing or until either party gives notice of termination.

The closing of this transaction is also conditioned upon execution of a joint ownership and operating agreement, the absence of material adverse effects, receipt of all construction permits, and appropriate regulatory approvals, as well as SMEPA's receipt of Rural Utilities Service (RUS) funding. In 2012, SMEPA received a conditional loan commitment from RUS for the purchase.

In 2012, on January 2, 2014, and on October 9, 2014, the Company received $150 million, $75 million, and $50 million, respectively, of interest-bearing refundable deposits from SMEPA to be applied to the purchase. While the expectation is that these amounts will be applied to the purchase price at closing, the Company would be required to refund the deposits upon the termination of the APA or within 15 days of a request by SMEPA for a full or partial refund. Given the interest-bearing nature of

the deposits and SMEPA's ability to request a refund, the deposits have been presented as a current liability in the balance sheet and as financing proceeds in the statement of cash flow. In July 2013, Southern Company entered into an agreement with SMEPA under which Southern Company has agreed to guarantee the obligations of the Company with respect to any required refund of the deposits.

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

Investment Tax Credits and Bonus Depreciation

The IRS allocated $279.0 million (Phase II) of Internal Revenue Code Section 48A tax credits to the Company in connection with the Kemper IGCC. Through December 31, 2014, the Company had recorded tax benefits totaling $276.4 million for the Phase II credits, of which approximately $210.0 million had been utilized through that date. These credits will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC and are dependent upon meeting the IRS certification requirements, including an in-service date no later than April 19, 2016 and 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. The Company currently expects to place the Kemper IGCC in service in the first half of 2016. In addition, a portion of the Phase II tax credits will be subject to recapture upon completion of SMEPA's proposed purchase of an undivided interest in the Kemper IGCC as described above.

On December 19, 2014, the Tax Increase Prevention Act of 2014 (TIPA) was signed into law. The TIPA retroactively extended several tax credits through 2014 and extended 50% bonus depreciation for property placed in service in 2014 (and for certain long-term production-period projects to be placed in service in 2015). The extension of 50% bonus depreciation had a positive impact on the Company's cash flows and combined with bonus depreciation allowed in 2014 under the American Taxpayer Relief Act of 2012, resulted in approximately $130 million of positive cash flows related to the combined cycle and associated common facilities portion of the Kemper IGCC for the 2014 tax year. The estimated cash flow benefit of bonus depreciation related to TIPA is expected to be approximately $45 million to $50 million for the 2015 tax year.

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

Section 174 Research and Experimental Deduction

Southern Company, on behalf of the Company, reduced tax payments for 2014 and included in its 2013 consolidated federal income tax return deductions for research and experimental (R&E) expenditures related to the Kemper IGCC. Due to the uncertainty related to this tax position, the Company recorded an unrecognized tax benefit of approximately $160 million as of December 31, 2014. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Other Matters

Sierra Club Settlement Agreement

On August 1, 2014, the Company entered into the Sierra Club Settlement Agreement that, among other things, requires the Sierra Club to dismiss or withdraw all pending legal and regulatory challenges of the Kemper IGCC and the scrubber project at Plant Daniel Units 1 and 2. In addition, the Sierra Club agreed to refrain from initiating, intervening in, and/or challenging certain legal and regulatory proceedings for the Kemper IGCC, including, but not limited to, the prudence review, and Plant Daniel for a period of three years from the date of the Sierra Club Settlement Agreement. On August 4, 2014, the Sierra Club filed all of the required motions necessary to dismiss or withdraw all appeals associated with certification of the Kemper IGCC and the Plant Daniel Units 1 and 2 scrubber project, which the applicable courts subsequently granted.

Under the Sierra Club Settlement Agreement, the Company agreed to, among other things, fund a $15 million grant payable over a 15-year period for an energy efficiency and renewable program and contribute $2 million to a conservation fund. In accordance with the Sierra Club Settlement Agreement, the Company paid $7 million in 2014, recognized in other income (expense), net in the statement of operations. 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. 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, and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) and begin operating those units solely on natural gas no later than April 2016. See Note 3 under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.

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.

In August 2014, a decision was made to cease coal operations at Greene County Steam Plant and convert to natural gas no later than April 16, 2016. As a result, active construction projects related to these assets were cancelled in September 2014. Associated amounts in CWIP of $5.6 million, reflecting the Company's share of the costs, were subsequently transferred to regulatory assets. See Note 3 under "Retail Regulatory Matters-Environmental Compliance Overview Plan" herein for additional information.

At December 31, 2014, 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 thousands)		
Greene County				
Units 1 and 2	40%	$ 102,384	$ 51,911	$ 902
Daniel				
Units 1 and 2	50%	$ 299,440	$ 155,606	$ 286,240

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.

See Note 3 under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama and Mississippi. 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:

	2014	2013	2012
		(in thousands)	
Federal —			
Current	$ (431,077)	$ 23,345	$ 1,212
Deferred	183,461	(342,870)	16,994
	(247,616)	(319,525)	18,206
State —			
Current	455	5,219	1,656
Deferred	(38,044)	(53,529)	694
	(37,589)	(48,310)	2,350
Total	$ (285,205)	$ (367,835)	$ 20,556

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:

	2014	2013
	(in thousands)	
Deferred tax liabilities —		
Accelerated depreciation	**$ 1,068,242**	$ 371,553
Property basis differences	**—**	130,679
ECM under recovered	**—**	1,777
Regulatory assets associated with AROs	**19,299**	16,764
Pensions and other benefits	**35,200**	23,769
Regulatory assets associated with employee benefit obligations	**67,727**	33,127
Regulatory assets associated with the Kemper IGCC	**61,561**	30,708
Rate differential	**89,040**	56,074
Federal effect of state deferred taxes	**1,279**	30,615
Fuel clause under recovered	**3,288**	—
Other	**52,215**	35,583
Total	**1,397,851**	730,649
Deferred tax assets —		
Fuel clause over recovered	**—**	7,741
Estimated loss on Kemper IGCC	**631,326**	472,000
Pension and other benefits	**92,232**	57,999
Property insurance	**24,315**	23,693
Premium on long-term debt	**20,694**	23,736
Unbilled fuel	**14,535**	12,136
AROs	**19,299**	16,764
Interest rate hedges	**4,544**	5,094
Kemper rate factor - regulatory liability retail	**108,312**	36,210
Property basis difference	**263,430**	—
ECM over recovered	**905**	—
Deferred state tax assets	**56,736**	—
Other	**15,111**	18,094
Total	**1,251,439**	673,467
Total deferred tax liabilities, net	**146,412**	57,182
Portion included in (accrued) prepaid income taxes, net	**121,049**	15,626
Deferred state tax asset	**17,388**	—
Accumulated deferred income taxes	**$ 284,849**	$ 72,808

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

At December 31, 2014, the tax-related regulatory assets were $226.2 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 to taxes applicable to capitalized interest.

At December 31, 2014, the tax-related regulatory liabilities were $9.4 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 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 $1.4 million, $1.2 million, and $1.2 million for 2014, 2013, and 2012, respectively. At December 31, 2014, all non-Kemper IGCC ITCs available to reduce federal income taxes payable had been utilized.

In 2010, the Company began recognizing ITCs associated with the construction expenditures related to the Kemper IGCC. At December 31, 2014, the Company had $276.4 million in unamortized ITCs associated with the Kemper IGCC, which will be amortized over the life of the Kemper IGCC once placed in service and are dependent upon meeting the IRS certification requirements, including an in-service date no later than April 19, 2016 and the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operation in accordance with the Internal Revenue Code. A portion of the tax credits will be subject to recapture upon successful completion of SMEPA's proposed purchase of an undivided interest in the Kemper IGCC.

Effective Tax Rate

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

	2014	2013	2012
Federal statutory rate	**(35.0)%**	(35.0)%	35.0%
State income tax, net of federal deduction	**(4.0)**	(3.7)	1.3
Non-deductible book depreciation	**0.1**	0.1	0.3
AFUDC-equity	**(7.8)**	(5.0)	(18.6)
Other	**0.1**	(0.1)	(1.2)
Effective income tax rate (benefit rate)	**(46.6)%**	(43.7)%	16.8%

The increase in the Company's 2014 effective tax rate (benefit rate), as compared to 2013, is primarily due to an increase in non-taxable AFUDC equity. The decrease in the Company's 2013 effective tax rate, as compared to 2012, is primarily due to an increase in the estimated losses associated with the Kemper IGCC and an increase in non-taxable AFUDC equity.

Unrecognized Tax Benefits

Changes during the year in unrecognized tax benefits were as follows:

	2014	2013	2012
		(in thousands)	
Unrecognized tax benefits at beginning of year	**$ 3,840**	$ 5,755	$ 4,964
Tax positions from current periods	**58,148**	226	1,186
Tax positions from prior periods	**102,833**	(2,141)	(26)
Settlements with taxing authorities	**—**	—	(369)
Balance at end of year	**$ 164,821**	$ 3,840	$ 5,755

The increases in tax positions from current periods and prior periods for 2014 relate to deductions for R&E expenditures related to the Kemper IGCC. See Note 3 under "Integrated Coal Gasification Combined Cycle – Section 174 Research and Experimental Deduction" for more information. The decrease in tax positions from prior periods for 2013 relates primarily to the tax accounting method change for repairs related to generation assets. See "Tax Method of Accounting for Repairs" below for additional information.

The impact on the Company's effective tax rate, if recognized, is as follows:

	2014	2013	2012
		(in thousands)	
Tax positions impacting the effective tax rate	**$ 4,341**	$ 3,840	$ 3,656
Tax positions not impacting the effective tax rate	**160,480**	—	2,099
Balance of unrecognized tax benefits	**$ 164,821**	$ 3,840	$ 5,755

The tax positions impacting the effective tax rate primarily relate to state income tax credits. The tax positions not impacting the effective tax rate for 2014 relate to a deduction for R&E related to the Kemper IGCC. The tax positions not impacting the

effective tax rate for 2012 relate to the tax accounting method change for repairs related to generation assets. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Accrued interest for unrecognized tax benefits was as follows:

	2014	2013	2012
		(in thousands)	
Interest accrued at beginning of year	$ 1,171	$ 772	$ 680
Interest accrued during the year	1,698	399	92
Balance at end of year	$ 2,869	$ 1,171	$ 772

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 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 federal income tax return and has received a partial acceptance letter from the IRS; however, the IRS has not finalized its audit. 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.

Tax Method of Accounting for Repairs

In 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. Additionally, in April 2013, the IRS issued Revenue Procedure 2013-24, which provides guidance for taxpayers related to the deductibility of repair costs associated with generation assets. Based on a review of the regulations, Southern Company incorporated provisions related to repair costs for generation assets into its consolidated 2012 federal income tax return and reversed all related unrecognized tax positions. In September 2013, the IRS issued Treasury Decision 9636, "Guidance Regarding Deduction and Capitalization of Expenditures Related to Tangible Property," which are final tangible property regulations applicable to taxable years beginning on or after January 1, 2014. Southern Company continues to review this guidance; however, these regulations are not expected to have a material impact on the Company's financial statements.

6. FINANCING

Bank Term Loans

In January 2014, the Company entered into an 18-month floating rate bank loan bearing interest based on one-month LIBOR. The term loan was for $250 million aggregate principal amount and the proceeds were used for working capital and other general corporate purposes, including the Company's continuous construction program.

At December 31, 2014 and 2013, the Company had $775 million and $525 million of bank loans outstanding, respectively, which are reflected in the statements of capitalization as securities due within one year and long-term debt.

These bank loans have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, 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, 2014, the Company was in compliance with its debt limits.

Senior Notes

At December 31, 2014 and 2013, the Company had $1.1 billion of senior notes outstanding. 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 $346.1 million, reflecting a premium of $76.1 million.

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31, 2014 and 2013 was as follows:

	2014	2013
	(in millions)	
Bank term loans	$ 775.0	$ —
Revenue bonds	—	11.3
Capitalized leases	2.7	2.5
Outstanding at December 31	$ 777.7	$ 13.8

Maturities through 2019 applicable to total long-term debt are as follows: $777.7 million in 2015, $302.8 million in 2016, $37.9 million in 2017, $3.1 million in 2018, and $128.2 million in 2019.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2014 and 2013 was $82.7 million.

Other Revenue Bonds

Other revenue bond obligations represent loans to the Company from a public authority of funds derived from the sale by such authority of revenue bonds issued to finance a portion of the costs of constructing the Kemper IGCC and related facilities.

In November 2013, the MBFC entered into an agreement to issue up to $33.75 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2013A (Mississippi Power Company Project) and up to $11.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2013B (Mississippi Power Company Project) for the benefit of the Company. In November 2013, the MBFC issued $11.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013B for the benefit of the Company.

In May 2014 and August 2014, the MBFC issued $12.3 million and $10.5 million, respectively, aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013A for the benefit of the Company and proceeds were used to reimburse the Company for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility related to the Kemper IGCC. In December 2014, the MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013A of $22.87 million and Series 2013B of $11.25 million were paid at maturity. The Company had $50.0 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2014 and 2013. The Company had no obligation as of December 31, 2014 and $11.3 million of such obligations related to taxable revenue bonds outstanding at December 31, 2013. Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.

The Company's agreements relating to the taxable revenue bonds include covenants limiting debt levels consistent with those described above under "Bank Term Loans."

Capital Leases

In September 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, 2014 of $80.0 million with an annual interest rate of 4.9%. 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 2014 were $6.5 million and will be $6.5 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.

Other Obligations

In 2012, January 2014, and October 2014, the Company received $150 million, $75 million, and $50 million, respectively, interest-bearing refundable deposits from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the sale is closed, the deposits bear interest at the Company's AFUDC rate adjusted for income taxes, which was 10.134% per annum for 2014, 9.932% per annum for 2013, and 9.967% per annum for 2012, and are refundable to SMEPA upon termination of the APA related to such purchase or within 15 days of a request by SMEPA for a full or partial refund.

In May 2014, the Company issued a 19-month floating rate promissory note to Southern Company for a loan bearing interest based on one-month LIBOR. This loan was for $220 million aggregate principal amount and the proceeds were used for working capital and other general corporate purposes, including the Company's construction program. This loan was repaid in September 2014.

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.

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.

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, 2014, committed credit arrangements with banks were as follows:

Expires				Executable Term-Loans		Due Within One Year	
2015	2016	Total	Unused	One Year	Two Years	Term Out	No Term Out
		(in millions)					
$135	$165	$300	$300	$25	$40	$65	$70

Subject to applicable market conditions, the Company expects to renew its bank credit arrangements, as needed, prior to expiration.

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 $300 million unused credit with banks is allocated to provide liquidity support to the Company's variable rate 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, 2014 was $40.1 million.

The Company makes short-term borrowings primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements.

At December 31, 2014 and 2013, there was no 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 2014, 2013, and 2012, the Company incurred fuel expense of $573.9 million, $491.3 million, and $411.2 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, 2014 of $38.4 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 operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total rent expense was $12.7 million, $10.1 million, and $11.1 million for 2014, 2013, and 2012, respectively.

The Company and Gulf Power have jointly entered into operating lease agreements for aluminum railcars for the transportation of coal at Plant Daniel. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value, or to renew the leases at the end of the lease term. The Company has one remaining operating lease which has 229 aluminum railcars. The Company and Gulf Power also have separate lease agreements for other railcars that do not contain a purchase option.

The Company's share (50%) of the leases, charged to fuel stock and recovered through the fuel cost recovery clause, was $4.9 million in 2014, $3.1 million in 2013, and $3.6 million in 2012. The Company's annual railcar lease payments for 2015 through 2017 will average approximately $1.6 million. The Company has no lease obligations for the period 2018 and thereafter.

In addition to railcar leases, the Company has other operating leases for fuel handling equipment at Plants Daniel and Watson and operating leases for barges and tow/shift boats for the transport of coal at Plant Watson. The Company's share (50% at Plant Daniel and 100% at Plant Watson) of the leases for fuel handling was charged to fuel handling expense in the amount of $0.2 million annually from 2012 through 2014. The Company's annual lease payment for 2015 is expected to be $0.1 million for fuel handling equipment. The Company charged to fuel stock and recovered through fuel cost recovery the barge transportation leases in the amount of $7.5 million in 2014, $6.7 million in 2013, and $7.3 million in 2012 related to barges and tow/shift boats. The Company's annual lease payment for 2015 with respect to these barge transportation leases is expected to be $1.8 million.

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's system employees ranging from line management to executives. As of December 31, 2014, there were 244 current and former employees of the Company participating in the stock option program. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the

grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. Stock options held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted stock options for 578,256 shares, 345,830 shares, and 278,709 shares, respectively. The weighted average grant-date fair value of stock options granted during 2014, 2013, and 2012, derived using the Black-Scholes stock option pricing model, was $2.20, $2.93, and $3.39, respectively.

The compensation cost and tax benefits related to the grant of Southern Company stock options to the Company's employees and the exercise of stock options are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. No cash proceeds are received by the Company upon the exercise of stock options. The amounts were not material for any year presented.

As of December 31, 2014, 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, 2014, 2013, and 2012 was $5.4 million, $2.7 million, and $4.9 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $2.1 million, $1.1 million, and $1.9 million for the years ended December 31, 2014, 2013, and 2012, respectively. As of December 31, 2014, the aggregate intrinsic value for the options outstanding and options exercisable was $18.4 million and $12.3 million, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount. Performance share units held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted performance share units of 49,579, 36,769, and 33,077, respectively. The weighted average grant-date fair value of performance share units granted during 2014, 2013, and 2012, 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 $37.54, $40.50, and $41.99, respectively.

The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. For the years ended December 31, 2014, 2013, and 2012, total compensation cost for performance share units recognized in income was $1.7 million, $1.5 million, and $1.2 million, respectively, with the related tax benefit also recognized in income of $0.6 million, $0.6 million, and $0.4 million, respectively. The compensation cost and tax benefits related to the grant of Southern Company performance share units to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2014, there was $1.8 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 20 months.

9. FAIR VALUE MEASUREMENTS

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

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.

- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

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

As of December 31, 2014, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Energy-related derivatives	$ —	$ 65	$ —	$ 65
Cash equivalents	114,900	—	—	114,900
Total	$ 114,900	$ 65	$ —	$ 114,965
Liabilities:				
Energy-related derivatives	$ —	$ 45,429	$ —	$ 45,429

As of December 31, 2013, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2013:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Energy-related derivatives	$ —	$ 4,803	$ —	$ 4,803
Cash equivalents	125,000	—	—	125,000
Total	$ 125,000	$ 4,803	$ —	$ 129,803
Liabilities:				
Energy-related derivatives	$ —	$ 10,281	$ —	$ 10,281
Foreign currency derivatives	—	1	—	1
Total	$ —	$ 10,282	$ —	$ 10,282

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, 2014 and 2013, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2014:	*(in thousands)*			
Cash equivalents:				
Money market funds	$ 114,900	None	Daily	Not applicable
As of December 31, 2013:				
Cash equivalents:				
Money market funds	$ 125,000	None	Daily	Not applicable

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2014 and 2013, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
2014	**$ 2,328,476**	**$ 2,382,050**
2013	$ 2,098,639	$ 2,045,519

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 and occasionally foreign currency 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 gross basis. See Note 9 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities and the cash impacts of settled foreign currency derivatives are recorded as investing activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Mississippi PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in electricity prices, the Company may enter into physical fixed-price or heat rate contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in 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 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 and are initially deferred in OCI before being recognized in the statements of operations 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 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, 2014, the net volume of energy-related derivative contracts for natural gas positions for the Company, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

Net Purchased mmBtu	Longest Hedge Date	Longest Non-Hedge Date
(in millions)		
54	2018	—

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to earnings for the next 12-month period ending December 31, 2015 are immaterial.

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, 2014, 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, 2015 are $1.4 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2022.

Foreign Currency Derivatives

The Company may enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates arising from purchases of equipment denominated in a currency other than U.S. dollars. Derivatives related to a firm commitment in a foreign currency transaction are accounted for as a fair value hedge where the derivatives' fair value gains or losses and the hedged items' fair value gains or losses are both recorded directly to earnings. Derivatives related to a forecasted transaction are accounted for as a cash flow hedge 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. Any ineffectiveness is typically recorded directly to earnings; however, the Company has regulatory approval allowing it to defer any ineffectiveness associated with firm commitments related to the Kemper IGCC to a regulatory asset. During 2011, certain fair value hedges were de-designated and subsequently settled in 2012. The ineffectiveness related to the de-designated hedges was recorded as a regulatory asset and was immaterial to the Company. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

At December 31, 2014, there were no foreign currency derivatives outstanding.

Derivative Financial Statement Presentation and Amounts

At December 31, 2014 and 2013, the fair value of energy-related derivatives and foreign currency derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in thousands)			*(in thousands)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 30**	$3,352	Other current liabilities	**$ 26,259**	$ 3,652
	Other deferred charges and assets	**22**	1,451	Other deferred credits and liabilities	**19,159**	6,629
Total derivatives designated as hedging instruments for regulatory purposes		**$ 52**	$4,803		**$ 45,418**	$10,281
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Foreign currency derivatives:	Other current assets	**$ —**	$ —	Other current liabilities	**$ —**	$ 1
Total		**$ 52**	$4,803		**$ 45,418**	$10,282

Energy-related derivatives not designated as hedging instruments were immaterial for 2014 and 2013. The derivative contracts of the Company are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related derivative contracts contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts at December 31, 2014 and 2013 are presented in the following tables.

	Fair Value			
Assets	**2014**	2013	**Liabilities**	**2014**	2013
	(in thousands)			*(in thousands)*	
Energy-related derivatives presented in the Balance Sheet [a]	**$ 65**	$ 4,803	Energy-related derivatives presented in the Balance Sheet [a]	**$ 45,429**	$10,282
Gross amounts not offset in the Balance Sheet [b]	**(64)**	(3,856)	Gross amounts not offset in the Balance Sheet [b]	**(64)**	(3,856)
Net energy-related derivative assets	**$ 1**	$ 947	**Net energy-related derivative liabilities**	**$ 45,365**	$ 6,426

(a) The Company does not offset fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.

(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

At December 31, 2014 and 2013, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	Balance Sheet Location	2014	2013	Balance Sheet Location	2014	2013
		(in thousands)			(in thousands)	
Energy-related derivatives:	Other regulatory assets, current	$ (26,259)	$ (3,652)	Other regulatory liabilities, current	$ 30	$ 3,352
	Other regulatory assets, deferred	(19,159)	(6,629)	Other regulatory liabilities, deferred	22	1,451
Total energy-related derivative gains (losses)		$ (45,418)	$(10,281)		$ 52	$ 4,803

The pre-tax effects of unrealized gains (losses) arising from energy-related derivative instruments not designated as hedging instruments was immaterial for 2014 and 2013.

For the years ended December 31, 2014, 2013, and 2012, the pre-tax effects of derivatives designated as cash flow hedging instruments on the statements of operations 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	2014	2013	2012	Statements of Operations Location	2014	2013	2012
	(in thousands)				(in thousands)		
Energy-related derivatives	$ —	$ —	$ —	Fuel	$ —	$ —	$ —
Interest rate derivatives	—	—	(774)	Interest Expense	(1,375)	(1,375)	(1,073)
Total	$ —	$ —	$ (774)		$ (1,375)	$ (1,375)	$ (1,073)

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2014, 2013, and 2012, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of operations were immaterial.

For the years ended December 31, 2014 and 2013, the pre-tax effects of foreign currency derivatives designated as fair value hedging instruments on the Company's statements of operations were immaterial. For the year ended December 31, 2012, the pre-tax effect of foreign currency derivatives designated as fair value hedging instruments, which include a pretax loss associated with the de-designated hedges prior to de-designation, was a $0.6 million gain. These amounts were offset by changes in the fair value of the purchase commitment related to equipment purchases. Therefore, there is no impact on the Company's statements of operations.

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, 2014, the Company's collateral posted with its derivative counterparties was immaterial.

At December 31, 2014, the fair value of derivative liabilities with contingent features was $9.9 million. However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $54.5 million, and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

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

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

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2014 and 2013 is as follows:

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss) After Dividends on Preferred Stock
		(in thousands)	
March 2014	**$ 331,161**	**$ (325,460)**	**$ (172,048)**
June 2014	**310,975**	**56,021**	**62,495**
September 2014	**354,623**	**(349,010)**	**(195,070)**
December 2014	**245,852**	**(70,721)**	**(24,058)**
March 2013	$ 245,934	$ (429,148)	$ (246,321)
June 2013	306,435	(388,395)	(219,110)
September 2013	325,206	(79,890)	(24,115)
December 2013	267,582	(24,412)	12,921

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 $70.0 million ($43.2 million after tax) in the fourth quarter 2014, $418.0 million ($258.1 million after tax) in the third quarter 2014, $380.0 million ($234.7 million after tax) in the first quarter 2014, $40.0 million ($24.7 million after tax) in the fourth quarter 2013, $150.0 million ($92.6 million after tax) in the third quarter 2013, $450.0 million ($277.9 million after tax) in the second quarter 2013, $462.0 million ($285.3 million after tax) in the first quarter 2013, and $78.0 million ($48.2 million after tax) in the fourth quarter 2012. In the aggregate, the Company has incurred charges of $2.05 billion ($1.26 billion after tax) as a result of changes in the cost estimate for the Kemper IGCC through December 31, 2014. 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 2010-2014
Mississippi Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in thousands)	**$ 1,242,611**	$ 1,145,157	$ 1,035,996	$ 1,112,877	$ 1,143,068
Net Income (Loss) After Dividends on Preferred Stock (in thousands)	**$ (328,681)**	$ (476,625)	$ 99,942	$ 94,182	$ 80,217
Cash Dividends on Common Stock (in thousands)	**$ —**	$ 71,956	$ 106,800	$ 75,500	$ 68,600
Return on Average Common Equity (percent)	**(15.43)**	(24.28)	7.14	10.54	11.49
Total Assets (in thousands)	**$ 6,756,728**	$ 5,848,209	$ 5,373,621	$ 3,671,842	$ 2,476,321
Gross Property Additions (in thousands)	**$ 1,388,711**	$ 1,773,332	$ 1,665,498	$ 1,205,704	$ 340,162
Capitalization (in thousands):					
Common stock equity	**$ 2,084,260**	$ 2,176,551	$ 1,749,208	$ 1,049,217	$ 737,368
Redeemable preferred stock	**32,780**	32,780	32,780	32,780	32,780
Long-term debt	**1,630,487**	2,167,067	1,564,462	1,103,596	462,032
Total (excluding amounts due within one year)	**$ 3,747,527**	$ 4,376,398	$ 3,346,450	$ 2,185,593	$ 1,232,180
Capitalization Ratios (percent):					
Common stock equity	**55.6**	49.7	52.3	48.0	59.8
Redeemable preferred stock	**0.9**	0.7	1.0	1.5	2.7
Long-term debt	**43.5**	49.6	46.7	50.5	37.5
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**152,453**	152,585	152,265	151,805	151,944
Commercial	**33,496**	33,250	33,112	33,200	33,121
Industrial	**482**	480	472	496	504
Other	**175**	175	175	175	187
Total	**186,606**	186,490	186,024	185,676	185,756
Employees (year-end)	**1,478**	1,344	1,281	1,264	1,280

SELECTED FINANCIAL AND OPERATING DATA 2010-2014 (continued)
Mississippi Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in thousands):					
Residential	$ 239,330	$ 241,956	$ 226,847	$ 246,510	$ 256,994
Commercial	257,189	265,506	250,860	263,256	266,406
Industrial	290,902	289,272	262,978	275,752	267,588
Other	7,222	2,405	6,768	6,945	6,924
Total retail	794,643	799,139	747,453	792,463	797,912
Wholesale — non-affiliates	322,659	293,871	255,557	273,178	287,917
Wholesale — affiliates	107,210	34,773	16,403	30,417	41,614
Total revenues from sales of electricity	1,224,512	1,127,783	1,019,413	1,096,058	1,127,443
Other revenues	18,099	17,374	16,583	16,819	15,625
Total	$ 1,242,611	$ 1,145,157	$ 1,035,996	$ 1,112,877	$ 1,143,068
Kilowatt-Hour Sales (in thousands):					
Residential	2,126,115	2,087,704	2,045,999	2,162,419	2,296,157
Commercial	2,859,617	2,864,947	2,915,934	2,870,714	2,921,942
Industrial	4,942,689	4,738,714	4,701,681	4,586,356	4,466,560
Other	40,595	40,139	38,588	38,684	38,570
Total retail	9,969,016	9,731,504	9,702,202	9,658,173	9,723,229
Wholesale — non-affiliates	4,190,812	3,929,177	3,818,773	4,009,637	4,284,289
Wholesale — affiliates	2,899,814	931,153	571,908	648,772	774,375
Total	17,059,642	14,591,834	14,092,883	14,316,582	14,781,893
Average Revenue Per Kilowatt-Hour (cents)*:					
Residential	11.26	11.59	11.09	11.40	11.19
Commercial	8.99	9.27	8.60	9.17	9.12
Industrial	5.89	6.10	5.59	6.01	5.99
Total retail	7.97	8.21	7.70	8.21	8.21
Wholesale	6.06	6.76	6.19	6.52	6.51
Total sales	7.18	7.73	7.23	7.66	7.63
Residential Average Annual Kilowatt-Hour Use Per Customer	13,934	13,680	13,426	14,229	15,130
Residential Average Annual Revenue Per Customer	$ 1,568	$ 1,585	$ 1,489	$ 1,622	$ 1,693
Plant Nameplate Capacity Ratings (year-end) (megawatts)	3,867	3,088	3,088	3,156	3,156
Maximum Peak-Hour Demand (megawatts):					
Winter	2,618	2,083	2,168	2,618	2,792
Summer	2,345	2,352	2,435	2,462	2,638
Annual Load Factor (percent)	59.4	64.7	61.9	59.1	57.9
Plant Availability Fossil-Steam (percent)**	87.6	89.3	91.5	87.7	93.8
Source of Energy Supply (percent):					
Coal	39.7	32.7	22.8	34.9	43.0
Oil and gas	55.3	57.1	63.9	51.5	41.9
Purchased power —					
From non-affiliates	1.4	2.0	2.0	1.4	1.3
From affiliates	3.6	8.2	11.3	12.2	13.8
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.
** Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

[This page intentionally left blank]

SOUTHERN POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Southern Power Company and Subsidiary Companies 2014 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, 2014.

Oscar C. Harper, IV
President and Chief Executive Officer

William C. Grantham
Vice President, Chief Financial Officer, and Treasurer
March 2, 2015

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, 2014 and 2013, and the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2014. 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-462 to II-484) present fairly, in all material respects, the financial position of Southern Power Company and Subsidiary Companies as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
March 2, 2015

DEFINITIONS

Term	Meaning
Adobe	Adobe Solar, LLC
Alabama Power	Alabama Power Company
AOCI	Accumulated other comprehensive income
Apex	Apex Nevada Solar, LLC
ASC	Accounting Standards Codification
Campo Verde	Campo Verde Solar, LLC
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
CWIP	Construction work in progress
EMC	Electric Membership Corporation
EPA	U.S. Environmental Protection Agency
EPE	El Paso Electric Company
FERC	Federal Energy Regulatory Commission
First Solar	First Solar, Inc.
FPL	Florida Power & Light Company
GAAP	Generally accepted accounting principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
Imperial Valley	SG2 Imperial Valley, LLC
IRS	Internal Revenue Service
ITC	Investment tax credit
Kay Wind	Kay Wind, LLC
KWH	Kilowatt-hour
Macho Springs	Macho Springs Solar, LLC
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 operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
SCE	Southern California Edison Company
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
SG2 Holdings	SG2 Holdings, LLC
Southern Company system	The Southern Company, the traditional operating companies, Southern Power Company, Southern Electric Generating Company, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.

SRE	Southern Renewable Energy, Inc.
SRP	Southern Renewable Partnerships, LLC
STR	Southern Turner Renewable Energy, LLC
traditional operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power
TRE	Turner Renewable Energy, LLC

OVERVIEW

Business Activities

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. The Company continually seeks opportunities to execute its strategy to create value through various transactions including acquisitions and sales of assets, construction of new power plants, and entry into PPAs primarily with investor owned utilities, independent power producers, municipalities, and electric cooperatives. In general, the Company has constructed or acquired new generating capacity only after entering into long-term PPAs for the new facilities.

The Company and TRE, through STR, a jointly-owned subsidiary owned 90% by Southern Power Company, acquired all of the outstanding membership interests of Adobe and Macho Springs on April 17, 2014 and May 22, 2014, respectively. The two solar facilities began commercial operation in May 2014 with the approximate 20-MW Adobe solar photovoltaic facility serving a PPA with SCE through 2034 and the approximate 50-MW Macho Springs solar photovoltaic facility serving a PPA with EPE also through 2034.

On October 22, 2014, the Company, through its subsidiaries SRP and SG2 Holdings, acquired all of the outstanding membership interests of Imperial Valley from a wholly-owned subsidiary of First Solar, the developer of the project. Imperial Valley constructed and owns an approximately 150-MW solar photovoltaic facility in Southern California. The solar facility began commercial operation on November 26, 2014 and at that time a subsidiary of First Solar was admitted as a minority member of SG2 Holdings. The entire output of the plant is contracted under a 25-year PPA with San Diego Gas & Electric Company, a subsidiary of Sempra Energy (SDG&E).

See FUTURE EARNINGS POTENTIAL – "Acquisitions" herein and Note 2 to the financial statements for additional information.

As of December 31, 2014, the Company had generating units totaling 9,074 MWs nameplate capacity in commercial operation, after taking into consideration its equity ownership percentage of the solar facilities. The average remaining duration of the Company's wholesale contracts is approximately 10 years, which reduces remarketing risk. The Company's renewable assets, including biomass and solar, have contract coverage in excess of 20 years. Taking into account the PPAs and capacity from the Taylor County and Decatur County Solar Projects, as discussed in "FUTURE EARNINGS POTENTIAL – Construction Projects" herein, and the acquisition of Kay Wind, which is expected to close in the fourth quarter 2015, as discussed in "FUTURE EARNINGS POTENTIAL – Acquisitions" herein, the Company had an average of 77% of its available capacity covered for the next five years (through 2019) and an average of 70% of its available capacity covered for the next 10 years (through 2024). The Company's future earnings will depend on the parameters of the wholesale market and the efficient operation of its wholesale generating assets. See FUTURE EARNINGS POTENTIAL herein for additional information.

Key Performance Indicators

To evaluate operating results and to ensure the Company's ability to meet its contractual commitments to customers, the Company focuses on several key performance indicators, including peak season equivalent forced outage rate (Peak Season EFOR), contract availability, and net income. Peak Season EFOR defines the hours during peak demand times when the Company's generating units are not available due to forced outages (a low metric is optimal). Contract availability measures the percentage of scheduled hours delivered. Net income is the primary measure of the Company's financial performance. The Company's actual performance in 2014 met or surpassed targets in these key performance areas. See RESULTS OF OPERATIONS herein for additional information on the Company's net income for 2014.

Earnings

The Company's 2014 net income was $172.3 million, a $6.8 million, or 4.1%, increase from 2013. The increase was primarily due to a decrease in income taxes primarily as a result of federal ITCs for new plants placed in service in 2014 and an increase in energy revenue from non-affiliates primarily related to new solar contracts. This increase was partially offset by increased depreciation, other operations and maintenance expenses, and interest expense.

The Company's 2013 net income was $165.5 million, a $9.8 million, or 5.6%, decrease from 2012. The decrease was primarily due to an increase in other operations and maintenance expenses and depreciation primarily due to an increase in costs related to scheduled outages and new plants placed in service, higher fuel and purchased power expenses, and higher interest expense. The

decrease was partially offset by an increase in capacity and energy revenues from non-affiliates and lower income tax expense associated with the net impact of federal ITCs received in 2013.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2014	2014	2013
		(in millions)	
Operating revenues	$ 1,501.2	$ 226.0	$ 89.2
Fuel	596.3	122.5	47.5
Purchased power	170.9	64.5	13.1
Other operations and maintenance	237.0	28.7	35.2
Depreciation and amortization	220.2	44.9	32.7
Taxes other than income taxes	21.5	0.1	2.1
Total operating expenses	1,245.9	260.7	130.6
Operating income	255.3	(34.7)	(41.4)
Interest expense, net of amounts capitalized	89.0	14.5	12.0
Other income (expense), net	5.6	9.7	(3.1)
Income taxes (benefit)	(3.2)	(49.1)	(46.7)
Net income	175.1	9.6	(9.8)
Less: Net income attributable to noncontrolling interests	2.8	2.8	—
Net income attributable to Southern Power Company	$ 172.3	$ 6.8	$ (9.8)

Operating Revenues

Operating revenues for 2014 were $1.5 billion, reflecting a $226.0 million, or 17.7%, increase from 2013. Details of operating revenues are as follows:

	2014	2013	2012
		(in millions)	
Capacity revenues —			
Affiliates	$ 117.8	$ 126.0	$ 125.9
Non-affiliates	428.4	446.4	372.6
Total	546.2	572.4	498.5
Energy revenues —			
Affiliates	35.4	23.8	35.6
Non-affiliates	602.2	427.1	346.7
Total	637.6	450.9	382.3
Total PPA revenues	1,183.8	1,023.3	880.8
Revenues not covered by PPA	314.6	245.3	298.0
Other revenues	2.8	6.6	7.2
Total Operating Revenues	$ 1,501.2	$ 1,275.2	$ 1,186.0

The increase in operating revenues was primarily due to a $121.0 million increase in energy revenues under PPAs with non-affiliates, resulting from a 24.0% increase in KWH sales, primarily due to increased demand and customer scheduling, and a 69.6% increase in the average price of energy, primarily due to higher natural gas prices, as well as, a $54.6 million increase which was the result of new solar contracts served by Plants Adobe, Macho Springs, and Imperial Valley, which began in 2014, and Plants Campo Verde and Spectrum, which began in 2013. Also contributing to the increase was a $34.2 million increase in

energy sales not covered by PPAs and a $33.3 million increase in sales under the Intercompany Interchange Contract (IIC), primarily due to increased generation and higher cost affiliate power. Additionally, there was an increase of $11.5 million in energy revenues under PPAs with affiliates primarily as a result of increased demand and customer scheduling. This increase was partially offset by an $18.0 million decrease in capacity revenues from non-affiliates primarily due to lower customer demand and the expiration of certain requirements contracts and an $8.1 million decrease in capacity revenues from affiliates primarily due to contract expirations.

Operating revenues in 2013 were $1.3 billion, an $89.2 million, or 7.5%, increase from 2012. The increase was primarily due to a $73.8 million increase in capacity revenues under PPAs with non-affiliates, resulting from a 10.6% increase in the total MWs of capacity under contract, primarily due to a new PPA served by Plant Nacogdoches, which began in June 2012, and an increase in capacity amounts under existing PPAs. Also contributing to the increase was an $80.4 million increase in energy sales under PPAs with non-affiliates, reflecting a 29.6% increase in the average price of energy and a $7.8 million increase related to new solar contracts, which began in 2013, served by Plants Campo Verde and Spectrum. This increase was partially offset by an $11.8 million decrease in energy sales under PPAs with affiliates, reflecting a 48.1% decrease in KWH sales primarily due to lower demand, partially offset by a 28.9% increase in the average price of energy. The increase in energy revenues from PPAs was partially offset by a $52.4 million decrease in energy sales not covered by PPAs, reflecting a 30.5% decrease in KWH sales primarily due to lower demand, partially offset by an 18.6% increase in the average price of energy.

Wholesale revenues from sales to affiliate companies will vary depending on demand and the availability and cost of generating resources at each company. Sales to affiliate companies that are not covered by PPAs are made in accordance with the IIC, as approved by the FERC.

Wholesale revenues from sales to non-affiliates will vary depending on the energy demand of those customers and their generation capacity, as well as the market prices of wholesale energy compared to the cost of the Company's energy. Increases and decreases in 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.

Capacity revenues are an integral component of the Company's PPAs with both affiliate and non-affiliate customers and generally represent the greatest contribution to net income. Energy under the PPAs is generally sold at variable cost or is indexed to published gas indices. Energy revenues also include fees for support services, fuel storage, and unit start charges.

See FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" below for additional information regarding the Company's PPAs.

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 fuel and purchased power expenditures are as follows:

	2014	2013	2012
		(in millions)	
Fuel	$ **596.3**	$ 473.8	$ 426.3
Purchased power-non-affiliates	**104.9**	76.0	80.4
Purchased power-affiliates	**66.0**	30.4	12.9
Total fuel and purchased power expenses	$ **767.2**	$ 580.2	$ 519.6

The Company's PPAs for natural gas-fired generation generally provide that the purchasers are responsible for substantially all of the cost of fuel. Consequently, any increase or decrease in fuel cost is generally accompanied by an increase or decrease in related fuel revenue and does 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 market or sold to affiliates under the IIC.

Purchased power expenses will vary depending on demand and the availability and cost of generating resources throughout the Southern Company system and other contract resources. Load requirements are submitted to the Southern Company system power pool on an hourly basis and are fulfilled with the lowest cost alternative, whether that is generation owned by Southern Power Company, affiliate-owned generation, or external purchases.

In 2014, total fuel and purchased power expenses increased $187.0 million, or 32.2%, compared to 2013, primarily due to a 19.7% increase in the average cost of natural gas and a 24.0% increase in the average cost of purchased power. The increase

reflected a 29.6% increase in the volume of KWHs purchased primarily as a result of higher demand and the availability of lower cost affiliate power.

In 2013, total fuel and purchased power expenses increased $60.6 million, or 11.7%, compared to 2012, primarily due to a 28.8% increase in the average cost of natural gas and a 21.1% increase in the average cost of purchased power. The increase was partially offset by a 12.8% net decrease in the volume of KWHs generated and purchased primarily due to lower demand and the availability of lower cost affiliate power.

In 2014, fuel expense increased $122.5 million, or 25.9%, compared to 2013. The increase was primarily due to a $91.3 million increase associated with the average cost of natural gas per KWH generated as well as a $31.2 million increase associated with the volume of KWHs generated.

In 2013, fuel expense increased $47.5 million, or 11.2%, compared to 2012. The increase was primarily due to a $104.1 million increase associated with the average cost of natural gas per KWH generated, partially offset by a $58.5 million decrease associated with the volume of KWHs generated.

In 2014, purchased power expense increased $64.5 million, or 60.6%, compared to 2013. The increase was primarily due to a $33.0 million increase associated with the average cost of purchased power and a $31.5 million increase associated with the volume of KWHs purchased.

In 2013, purchased power expense increased $13.1 million, or 14.0%, compared to 2012. The increase was primarily due to an $18.3 million increase associated with the average cost of purchased power, partially offset by a $5.3 million decrease associated with the volume of KWHs purchased.

Other Operations and Maintenance Expenses

In 2014, other operations and maintenance expenses increased $28.7 million, or 13.8%, compared to 2013. The increase was primarily due to a $10.6 million increase in other generation expenses primarily related to labor and repairs as well as a $7.8 million increase primarily as a result of increased business development costs and support services. Also contributing to the increase was a $6.6 million increase in costs related to new plants placed in service, including Plants Spectrum and Campo Verde in 2013, and Plants Adobe, Macho Springs and Imperial Valley in 2014, and a $2.2 million increase in employee compensation.

In 2013, other operations and maintenance expenses increased $35.2 million, or 20.4%, compared to 2012. The increase was primarily due to a $21.8 million increase related to scheduled outage costs at Plants Franklin and Wansley, $6.2 million in additional costs related to new plant additions, including Plants Nacogdoches, Apex, Granville, and Cleveland in 2012 and Plants Spectrum and Campo Verde in 2013, and a $1.4 million increase in transmission costs.

Depreciation and Amortization

In 2014, depreciation and amortization increased $44.9 million, or 25.6%, compared to 2013. The increase was primarily due to a $25.2 million increase in depreciation resulting from an increase in plant in service, including the addition of Plants Spectrum and Campo Verde in 2013, and Plants Adobe, Macho Springs, and Imperial Valley in 2014, an $8.4 million increase related to equipment retirements resulting from accelerated outage work, and a $5.9 million increase in component depreciation resulting from increased production at gas-fired plants.

In 2013, depreciation and amortization increased $32.7 million, or 22.9%, compared to 2012. The increase was primarily due to a $23.8 million increase in depreciation resulting from an increase in plant in service, including the additions of Plants Nacogdoches, Apex, Granville, and Cleveland in 2012 and Plants Spectrum and Campo Verde in 2013, a $3.5 million increase for outage related capital costs, and a $2.4 million increase resulting from higher depreciation rates driven by major outages occurring in 2013.

See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Depreciation" herein for additional information regarding the Company's ongoing review of depreciation estimates and change to component depreciation. See also Note 1 to the financial statements under "Depreciation" for additional information.

Interest Expense, Net of Amounts Capitalized

In 2014, interest expense, net of amounts capitalized increased $14.5 million, or 19.5%, compared to 2013. The increase was primarily due to a $9.3 million decrease in capitalized interest resulting from the completion of Plants Spectrum and Campo Verde in 2013 and an increase of $5.1 million in interest expense related to senior notes.

In 2013, interest expense, net of amounts capitalized increased $12.0 million, or 19.2%, compared to 2012. The increase was primarily due to a $19.1 million decrease in capitalized interest resulting from the completion of Plants Nacogdoches and

Cleveland in 2012, partially offset by a $9.2 million increase in capitalized interest associated with the construction of Plants Spectrum and Campo Verde in 2013.

Other Income (Expense), Net

In 2014, other income (expense), net increased $9.7 million compared to 2013. The increase in 2014 was primarily due to the recognition of a bargain purchase gain arising from a solar acquisition. Additionally, net income attributable to noncontrolling interests of approximately $3.9 million was included in other income (expense), net in 2013. See Note 10 to the financial statements for additional information on noncontrolling interests.

In 2013, other income (expense), net decreased $3.1 million compared to 2012. The decrease in 2013 was primarily due to increased earnings of STR, which resulted in a larger allocation of earnings to noncontrolling interest.

Income Taxes (Benefit)

In 2014, income taxes (benefit) decreased $49.1 million, or 107.0%, compared to 2013. The decrease was primarily due to a $20.1 million increase in tax benefits primarily from federal ITCs for solar plants placed in service in 2014, a $19.9 million decrease associated with lower pre-tax earnings, and a $10.5 million reduction in deferred income taxes as a result of the impact of state apportionment changes and beneficial changes in certain state income tax laws.

In 2013, income taxes (benefit) decreased $46.7 million, or 50.4%, compared to 2012. The decrease was primarily due to a $24.2 million increase in tax benefits from federal ITCs for solar plants placed in service in 2013 and a $20.9 million decrease associated with lower pre-tax earnings.

See 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 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; and the Company's ability to execute its acquisition and value creation strategy, including successfully expanding investments in renewable energy projects, and to construct generating facilities, including the impact of ITCs.

Other factors that could influence future earnings include weather, demand, cost of generating units within the power pool, and operational limitations.

Power Sales Agreements

The Company'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. 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.

The Company has assumed or entered into PPAs with some of Southern Company's traditional operating companies, other investor owned utilities, independent power producers, municipalities, electric cooperatives, and an energy marketing firm. Although some of the Company's PPAs are with the traditional operating companies, the Company's generating facilities are not in the traditional operating companies' regulated rate bases, and the Company is not able to seek recovery from the traditional operating companies' ratepayers for construction, repair, environmental, or maintenance costs. The Company expects that the capacity payments in the PPAs will produce sufficient cash flows to cover costs, pay debt service, and provide an equity return.

However, the Company's overall profit will depend on numerous factors, including efficient operation of its generating facilities and demand under the Company's PPAs.

As a general matter, substantially all of the Company's PPAs (excluding solar) provide that the purchasers are responsible for either procuring the fuel or reimbursing the Company for the cost of fuel 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.

The Company's solar sales are also through long-term PPAs where the customer purchases the entire energy output of a dedicated solar facility.

Capacity charges that form part of the PPA payments (excluding solar) are designed to recover fixed and variable operation and maintenance costs based on dollars-per-kilowatt year or energy charges based on dollars-per-MW hour. In general, to reduce the Company's exposure to certain operation and maintenance costs, it has long-term service agreements (LTSA) with General Electric International, Inc., Siemens Electric, Inc., First Solar, and NVT Licenses, LLC relating to such vendors' applicable equipment.

Many of the Company's PPAs have provisions that require the posting of collateral or an acceptable substitute guarantee in the event that S&P or Moody's downgrades the credit ratings of the counterparty to an unacceptable credit rating or if the counterparty is not rated or fails to maintain a minimum coverage ratio. The PPAs are expected to provide the Company with a stable source of revenue during their respective terms.

The Company is working to maintain and expand its share of the wholesale market. The Company expects that additional demand for capacity will begin to develop within some of its market areas beginning in the 2015-2017 timeframe. Taking into account the PPAs and capacity from the Taylor County and Decatur County Solar Projects, as discussed in "Construction Projects" herein, and the acquisition of Kay Wind, which is expected to close in the fourth quarter 2015, as discussed in "Acquisitions" herein, the Company had an average of 77% of its available capacity covered for the next five years (through 2019) and an average of 70% of its available capacity covered for the next 10 years (through 2024).

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; 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 regulatory or legislative changes cannot be determined at this time.

Because the Company's units are newer gas-fired and renewable generating facilities, costs associated with environmental compliance for these facilities have been less significant than for similarly situated coal-fired generating facilities or older gas-fired 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

Each of the states in which the Company has fossil generation is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I beginning in 2015 and Phase II beginning in 2017. In 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety, but on April 29, 2014, the U.S. Supreme Court overturned that decision and remanded the case back to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The U.S. Court

of Appeals for the District of Columbia Circuit granted the EPA's motion to lift the stay of the rule, and the first phase of CSAPR took effect on January 1, 2015.

In 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units), during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

In February 2013, the EPA proposed a rule that would require certain states to revise 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). The EPA proposed to supplement the 2013 proposed rule on September 17, 2014, making it more stringent. The EPA has entered into a settlement agreement requiring it to finalize the proposed rule by May 22, 2015. The proposed rule would require states subject to the rule (including Alabama, Florida, Georgia, and North Carolina) to revise their SSM provisions within 18 months after issuance of the final 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. The impacts of CSAPR, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of the proposed rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. These regulations could result in additional compliance costs that could affect results of operations, cash flows, and financial condition if such costs are not recovered through PPAs. Further, higher costs that are recovered through regulated rates at other utilities could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

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 on October 14, 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

In June 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing revised technology-based limits for certain wastestreams from steam electric power plants. The EPA has entered into a consent decree requiring it to finalize revisions to the steam electric effluent guidelines by September 30, 2015. The ultimate impact of the rule will also depend on the specific technology requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

These proposed and final 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, higher costs that are recovered through regulated rates at other utilities could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Global Climate Issues

In 2014, the EPA published three sets of proposed standards that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. On January 8, 2014, the EPA published proposed standards for new units, and, on June 18, 2014, the EPA published proposed standards governing existing units, known as the Clean Power Plan, and separate standards governing CO_2 emissions from modified and reconstructed units. The EPA's proposed Clean Power Plan establishes guidelines for states to develop plans to address CO_2 emissions from existing fossil fuel-fired electric generating units. The EPA's proposed guidelines establish state-specific interim and final CO_2 emission rate goals to be achieved between 2020 and 2029 and 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. 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 market-based contracts. Further, higher costs that are recovered through regulated rates at other utilities could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

The Southern Company system filed comments on the EPA's proposed Clean Power Plan on December 1, 2014. These comments addressed legal and technical issues in addition to providing a preliminary estimated cost of complying with the proposed

guidelines utilizing one of the EPA's compliance scenarios. Costs associated with this proposal could be significant to the utility industry and the Southern Company system. However, the ultimate financial and operational impact of the proposed Clean Power Plan on the Southern Company system cannot be determined at this time and will depend upon numerous known and unknown factors. Some of the unknown factors include: the structure, timing, and content of the EPA's final guidelines; individual state implementation of these guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

Over the past several years, the U.S. Congress has also considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2013 greenhouse gas emissions were approximately 9 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2014 greenhouse gas emissions on the same basis is approximately 11 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.

Income Tax Matters

Tax Credits

In 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA). Major tax incentives in the ARRA included renewable energy incentives. In January 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several renewable energy incentives through 2013, including extending federal ITCs for biomass projects which began construction before January 1, 2014. The current law provides for a 30% federal ITC for solar facilities placed in service through 2016 and, unless extended, will adjust to 10% for solar facilities placed in service thereafter. The Company qualified for ITCs related to Plants Adobe, Apex, Campo Verde, Cimarron, Granville, Imperial Valley, Macho Springs, Nacogdoches, and Spectrum, which have had and will continue to have a material impact on cash flows and net income. On December 19, 2014, the Tax Increase Prevention Act of 2014 (TIPA) was signed into law. The TIPA extended the production tax credit for wind and certain other renewable sources of electricity to facilities for which construction had commenced by the end of 2014. See Note 1 to the financial statements under "Income and Other Taxes" and Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Bonus Depreciation

The TIPA additionally extended 50% bonus depreciation for property placed in service in 2014 (and for certain long-term production-period projects to be placed in service in 2015). The extension of 50% bonus depreciation will have a positive impact on the Company's cash flows, of approximately $110 million.

Acquisitions

Adobe Solar, LLC

On April 17, 2014, the Company and TRE, through STR, a jointly-owned subsidiary owned 90% by the Company, acquired all of the outstanding membership interests of Adobe from Sun Edison, LLC, the original developer of the project. Adobe constructed and owns an approximately 20-MW solar generating facility in Kern County, California. The solar facility began commercial operation on May 21, 2014 and the entire output of the plant is contracted under a 20-year PPA with SCE. See Note 2 to the financial statements for additional information.

Macho Springs Solar, LLC

On May 22, 2014, the Company and TRE, through STR, acquired all of the outstanding membership interests of Macho Springs from First Solar Development, LLC, the original developer of the project. Macho Springs constructed and owns an approximately 50-MW solar photovoltaic facility in Luna County, New Mexico. The solar facility began commercial operation on May 23, 2014 and the entire output of the plant is contracted under a 20-year PPA with EPE. See Note 2 to the financial statements for additional information.

SG2 Imperial Valley, LLC

On October 22, 2014, the Company, through its subsidiaries SRP and SG2 Holdings, acquired all of the outstanding membership interests of Imperial Valley from a wholly-owned subsidiary of First Solar, the developer of the project. Imperial Valley constructed and owns an approximately 150-MW solar photovoltaic facility in Southern California. The solar facility began commercial operation on November 26, 2014 and the entire output of the plant is contracted under a 25-year PPA with SDG&E.

In connection with this acquisition, at substantial completion, on November 26, 2014, a subsidiary of First Solar was admitted as a minority member of SG2 Holdings. Ultimately, the Company indirectly owns 100% of the class A membership interests of SG2 Holdings and is entitled to 51% of all cash distributions from SG2 Holdings, and First Solar indirectly owns 100% of the class B membership interests of SG2 Holdings and is entitled to 49% of all cash distributions from SG2 Holdings. In addition, the Company is entitled to substantially all of the federal tax benefits with respect to this transaction. See Note 2 to the financial statements for additional information.

Kay County Wind Facility

On February 24, 2015, the Company, through its wholly-owned subsidiary SRE, entered into a purchase agreement with Kay Wind Holdings, LLC, a wholly-owned subsidiary of Apex Clean Energy Holdings, LLC, the developer of the project, to acquire all of the outstanding membership interests of Kay Wind for approximately $492 million, with potential purchase price adjustments based on performance testing. Kay Wind is constructing an approximately 299-MW wind facility in Kay County, Oklahoma. The wind facility is expected to begin commercial operation in late 2015, and the entire output of the facility is contracted under separate 20-year PPAs with Westar Energy, Inc. and Grand River Dam Authority. The acquisition is expected to close in the fourth quarter 2015 subject to Kay Wind achieving certain financing, construction, and project milestones, and various customary conditions to closing, and is included in the capital program estimates described under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein. See Note 2 to the financial statements for additional information.

Construction Projects

Taylor County Solar Project

On December 17, 2014, the Company announced that it will build an approximately 131-MW solar photovoltaic facility in Taylor County, Georgia. Construction of the facility is expected to begin in September 2015. Commercial operation is scheduled to begin in the fourth quarter of 2016, and the entire output of the facility is contracted under separate 25-year PPAs with Cobb Electric Membership Corp., Flint Electric Membership Corp., and Sawnee Electric Membership Corp. The total estimated cost of the facility is expected to be between $230 million and $250 million, and is included in the capital program estimates described under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

Decatur County Solar Projects

In February 2015, the Company announced that it will build two solar photovoltaic facilities, the Decatur Parkway Solar Project and the Decatur County Solar Project. These two projects, approximately 80-MW and 19-MW, respectively, will be constructed on separate sites in Decatur County, Georgia. The construction of the Decatur Parkway Solar Project commenced in February 2015 while the construction of the Decatur County Solar Project is expected to commence in June 2015. Both projects are expected to begin commercial operation in late 2015, and the entire output of each project is contracted to Georgia Power. The output of the Decatur Parkway Solar Project is contracted under a 25-year PPA with Georgia Power and the entire output of the Decatur County Solar Project is contracted under a separate 20-year PPA with Georgia Power. The total estimated cost of the facilities is expected to be between $200 million and $220 million, which includes the acquisition price for all of the outstanding membership interests of Decatur Parkway Solar Project, LLC and Decatur County Solar Project, LLC from TradeWind Energy, Inc. and is included in the capital program estimates described under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

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 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 classified as leases are accounted for as operating leases and the associated lease revenue is recognized on a straight-line basis over the term of the contract. Energy revenues and other contingent revenues are recognized in the period the energy is delivered or the service is rendered. All revenues under solar PPAs are accounted for as contingent revenues and recognized as services are performed.

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 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. Energy revenues are recognized in the period the energy is delivered or the service is rendered. Revenues are recorded on a gross basis in accordance with GAAP. 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 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 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 net income.

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 consist of acquired PPAs from certain acquisitions that are amortized over the term of the respective PPAs, and goodwill resulting from certain acquisitions. The Company evaluates the carrying value of these assets in accordance with accounting standards whenever indicators of potential impairment exist, or annually in the case of goodwill. 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. The Company accounts for business acquisitions from non-affiliates as business combinations. Accordingly, the Company includes these operations in the 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 in accordance with GAAP 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.

Depreciation

Beginning in 2014, the Company changed to component depreciation, where the depreciation of the original cost of assets is computed principally by the straight-line method over the estimated useful lives of assets determined by management. Certain 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. The primary assets in property, plant, and equipment are power plants, which have estimated useful lives ranging from 35 to 45 years. The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes that could have a material impact on net income in the near term.

When property subject to depreciation is retired or otherwise disposed of in the normal course of business, the applicable cost and accumulated depreciation is removed from the accounts and a gain or loss is recognized.

Prior to 2014, the Company computed depreciation on the original cost of assets under the straight-line method and applied a composite depreciation rate based on the assets' estimated useful lives determined by management.

Investment Tax Credits

Under the ARRA and ATRA, 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. See Note 1 to the financial statements under "Income and Other Taxes" for additional information.

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2014. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements 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 $602.4 million in 2014. Net cash provided from operating activities totaled $604.4 million in 2013, an increase of $31.2 million compared to 2012. This increase was primarily due to an increase in cash received from federal ITCs.

Net cash used for investing activities totaled $813.7 million, $696.0 million, and $332.5 million in 2014, 2013, and 2012, respectively. Net cash used for investing activities in 2014 was primarily due to the Adobe, Macho Springs, and Imperial Valley acquisitions. Net cash used for investing activities in 2013 was primarily due to the Campo Verde acquisition and the construction of the Spectrum and Campo Verde solar facilities. Net cash used for investing activities in 2012 was primarily due to the Apex, Spectrum, and Granville acquisitions, construction of Plants Nacogdoches and Cleveland, and payments pursuant to LTSAs.

Net cash provided from financing activities totaled $217.2 million and $131.8 million in 2014 and 2013, respectively. Net cash used for financing activities totaled $229.0 million in 2012. Net cash provided from financing activities in 2014 was primarily due to the issuance of commercial paper. Net cash provided from financing activities in 2013 was primarily the result of the issuance of new senior notes. Net cash used for financing activities in 2012 was primarily due to payment of common stock dividends and a decrease in notes payable.

Significant asset changes in the balance sheet during 2014 included an increase in property, plant, and equipment, primarily due to the acquisition of Adobe, Macho Springs, and Imperial Valley and an increase in deferred income taxes, current, due to the carryforward of federal ITCs arising from certain solar acquisitions.

Significant liability and stockholder's equity changes in the balance sheet during 2014 included an increase in federal ITCs due to new solar facilities placed in service, including Adobe, Macho Springs, and Imperial Valley and an increase in deferred income taxes primarily due to bonus depreciation on those new solar facilities, and an increase in notes payable due to the issuance of commercial paper.

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, 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.

The issuance of securities by Southern Power Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, Southern Power Company files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the FERC, 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.

As of December 31, 2014, the Company's current liabilities exceeded current assets by $320.1 million due to the long-term debt maturing in 2015 and the use of short-term debt as a funding source, as well as cash needs, which can fluctuate significantly due to the seasonality of the business. In 2015, the Company expects to utilize the capital markets and commercial paper markets as the source of funds for the majority of its maturities.

To meet liquidity and capital resource requirements, the Company had at December 31, 2014 cash and cash equivalents of approximately $74.6 million and Southern Power Company had a committed credit facility of $500 million (Facility) expiring in

2018. As of December 31, 2014, the total amount available under the Facility was $488 million. The Facility does not contain a material adverse change clause applicable to borrowing. Subject to applicable market conditions, Southern Power Company plans to renew the Facility prior to its expiration.

The Facility contains a covenant that limits the ratio of debt to capitalization (each 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. Southern Power Company is currently in compliance with all covenants in 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. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes.

Details of short-term borrowings were as follows:

	Commercial Paper at the End of the Period		Commercial Paper During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2014	**$ 195**	**0.4%**	**$ 54**	**0.4%**	**$ 445**
December 31, 2013	$ —	N/A	$ 117	0.4%	$ 271
December 31, 2012	$ 71	0.5%	$ 170	0.5%	$ 309

(a) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2014, 2013, and 2012.

The Company believes the need for working capital can be adequately met by utilizing the commercial paper program, the Facility, and cash.

Financing Activities

During 2014, the Company prepaid $9.5 million of long-term debt payable to TRE and issued $0.1 million due June 15, 2032, $0.8 million due April 30, 2033, $3.9 million due April 30, 2034, and $5.4 million due May 31, 2034 under promissory notes payable to TRE related to the financing of Apex, Campo Verde, Adobe, and Macho Springs, respectively.

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

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and Baa2, or BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, and energy price risk management.

The maximum potential collateral requirements under these contracts at December 31, 2014 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and Baa2	$ 9
At BBB- and/or Baa3	301
Below BBB- and/or Baa3	1,019

Included in these amounts are certain agreements that could require collateral in the event that one or more power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market.

In addition, the Company has a PPA that could require collateral, but not accelerated payment, in the event of a downgrade of Southern Power Company's credit. The PPA requires credit assurances without stating a specific credit rating. The amount of collateral required would depend upon actual losses, if any, resulting from a credit downgrade.

Market Price Risk

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 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, 2014, the Company had $18.8 million of long-term variable rate debt 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.

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.

The changes in fair value of energy-related derivative contracts associated with both power and natural gas positions, none of which are designated as hedges, for the years ended December 31 were as follows:

	2014 Changes	2013 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$ —	$ 0.8
Contracts realized or settled	**0.6**	(0.8)
Current period changes[(a)]	**1.3**	—
Contracts outstanding at the end of the period, assets (liabilities), net	**$ 1.9**	$ —

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

The changes in contracts outstanding were attributable to both the volume and the prices of power and natural gas as follows:

	December 31, 2014	December 31, 2013
Power – net purchased or (sold)		
MWH (in millions)	**(0.5)**	0.2
Weighted average contract cost per MWH above (below) market prices (in dollars)	**$ 11.32**	$ (2.22)
Natural gas net purchased		
Commodity – mmBtu	**3.4**	1.6
Commodity – weighted average contract cost per mmBtu above (below) market prices (in dollars)	**$ 1.02**	$ (0.08)

At December 31, 2014, the net fair value of energy-related derivative contracts that were not designated as hedging instruments was $1.9 million. For the Company's energy-related derivatives not designated as hedging instruments, a portion of the pre-tax realized and unrealized gains and losses is associated with hedging fuel price risk of certain PPA customers and has no impact on net income or on fuel expense as presented in the Company's statements of income. As a result, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the Company's statements of income were not material for any year presented. This third party hedging activity was discontinued prior to the end of 2014.

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 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. See Note 8 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, 2014 were as follows:

	Fair Value Measurements December 31, 2014			
	Total Fair Value	Maturity		
		Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ —	$ —	$ —	$ —
Level 2	1.9	1.9	—	—
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ 1.9	$ 1.9	$ —	$ —

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 be $1.4 billion for 2015, $1.3 billion for 2016, and $407.0 million for 2017. The construction program is subject to periodic review and revision. These amounts include estimates for potential plant acquisitions and new construction. In addition, the construction 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 changes in factors such as: business conditions; environmental statutes and regulations; FERC rules and regulations; load projections; legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital.

In addition, pursuant to an agreement with TRE, on or after November 25, 2015, or earlier in the event of the death of the controlling member of TRE, TRE may require the Company to purchase its noncontrolling interest in STR at fair market value.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, leases, derivative obligations, 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

	2015	2016-2017	2018-2019	After 2019	Total
			(in millions)		
Long-term debt[a] —					
Principal	$ 525.3	$ —	$ —	$ 1,093.8	$ 1,619.1
Interest	72.5	117.4	117.4	1,238.1	1,545.4
Financial derivative obligations[b]	3.5	0.1	—	—	3.6
Operating leases[c]	4.5	9.1	9.3	157.2	180.1
Unrecognized tax benefits[d]	4.7	—	—	—	4.7
Purchase commitments —					
Capital[e]	1,306.0	1,546.0	—	—	2,852.0
Fuel[f]	367.2	625.0	572.4	183.2	1,747.8
Purchased power[g]	53.5	77.4	80.5	83.8	295.2
Other[h]	52.9	226.7	158.8	560.4	998.8
Transmission agreements[i]	7.9	15.0	6.8	—	29.7
Total	$ 2,398.0	$ 2,616.7	$ 945.2	$ 3,316.5	$ 9,276.4

(a) All amounts are reflected based on final maturity dates. The Company plans 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 for the Plant Stanton Unit A land lease are subject to annual price escalation based on the Consumer Price Index for All Urban Consumers.

(d) See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(e) The Company provides estimated capital expenditures for a three year period. Amounts represent current estimates of total expenditures, excluding capital expenditures covered under LTSAs. See Note (h) below.

(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, 2014.

(g) Purchased power commitments of $37.6 million in 2015, $77.4 million in 2016-2017, $80.5 million in 2018-2019, and $83.8 million after 2019 will be resold under a third party agreement at cost.

(h) Includes LTSAs, capital leases, and operation and maintenance agreements. LTSAs include price escalation based on inflation indices.

(i) Transmission commitments are based on Southern Company's current tariff rate for point-to-point transmission.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2014 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for the Company's business, customer growth, economic recovery, fuel and environmental cost recovery, current and proposed environmental regulations and related compliance plans and estimated expenditures, 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 of acquisitions and construction projects, filings with federal regulatory authorities, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water and emissions of sulfur, nitrogen, CO_2, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of generating facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any operational and 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 ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and

- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2014, 2013, and 2012
Southern Power Company and Subsidiary Companies 2014 Annual Report

	2014	2013	2012
		(in thousands)	
Operating Revenues:			
Wholesale revenues, non-affiliates	$ 1,115,880	$ 922,811	$ 753,653
Wholesale revenues, affiliates	382,523	345,799	425,180
Other revenues	2,846	6,616	7,215
Total operating revenues	1,501,249	1,275,226	1,186,048
Operating Expenses:			
Fuel	596,319	473,805	426,257
Purchased power, non-affiliates	104,871	75,954	80,438
Purchased power, affiliates	66,033	30,415	12,915
Other operations and maintenance	237,061	208,366	173,074
Depreciation and amortization	220,174	175,295	142,624
Taxes other than income taxes	21,512	21,416	19,309
Total operating expenses	1,245,970	985,251	854,617
Operating Income	255,279	289,975	331,431
Other Income and (Expense):			
Interest expense, net of amounts capitalized	(88,992)	(74,475)	(62,503)
Other income (expense), net	5,560	(4,072)	(1,022)
Total other income and (expense)	(83,432)	(78,547)	(63,525)
Earnings Before Income Taxes	171,847	211,428	267,906
Income taxes (benefit)	(3,228)	45,895	92,621
Net Income	175,075	165,533	175,285
Less: Net income attributable to noncontrolling interests	2,775	—	—
Net Income Attributable to Southern Power Company	$ 172,300	$ 165,533	$ 175,285

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2014, 2013, and 2012
Southern Power Company and Subsidiary Companies 2014 Annual Report

	2014	2013	2012
		(in thousands)	
Net Income	**$ 175,075**	$ 165,533	$ 175,285
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $-, and $(90), respectively	—	—	(136)
Reclassification adjustment for amounts included in net income, net of tax of $169, $2,357, and $3,919, respectively	**367**	3,695	6,189
Total other comprehensive income	**367**	3,695	6,053
Less: Comprehensive income attributable to noncontrolling interests	**2,775**	—	—
Comprehensive Income Attributable to Southern Power Company	**$ 172,667**	$ 169,228	$ 181,338

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2014, 2013, and 2012
Southern Power Company and Subsidiary Companies 2014 Annual Report

	2014	2013	2012
		(in thousands)	
Operating Activities:			
Net income	**$ 175,075**	$ 165,533	$ 175,285
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization	**225,234**	183,239	156,268
Deferred income taxes	**(168,110)**	171,301	228,780
Investment tax credits	**73,512**	158,096	45,047
Amortization of investment tax credits	**(11,399)**	(5,535)	(2,633)
Deferred revenues	**(20,860)**	(18,477)	(12,633)
Mark-to-market adjustments	**(1,894)**	850	(9,275)
Other, net	**11,629**	3,335	3,104
Changes in certain current assets and liabilities —			
-Receivables	**(25,596)**	(11,178)	(1,384)
-Fossil fuel stock	**(2,576)**	2,438	(8,578)
-Materials and supplies	**(3,613)**	(8,410)	(7,825)
-Prepaid income taxes	**35,284**	(29,609)	(3,223)
-Other current assets	**(1,822)**	(2,219)	(1,624)
-Accounts payable	**30,352**	(11,572)	10,514
-Accrued taxes	**284,348**	(299)	431
-Accrued interest	**1,166**	6,093	385
-Other current liabilities	**1,646**	777	492
Net cash provided from operating activities	**602,376**	604,363	573,131
Investing Activities:			
Property additions	**(20,566)**	(500,756)	(116,633)
Cash paid for acquisitions	**(730,509)**	(132,163)	(124,059)
Change in construction payables	**(279)**	(4,072)	(27,387)
Payments pursuant to long-term service agreements	**(60,554)**	(57,269)	(63,932)
Other investing activities	**(1,756)**	(1,725)	(446)
Net cash used for investing activities	**(813,664)**	(695,985)	(332,457)
Financing Activities:			
Increase (decrease) in notes payable, net	**194,917**	(70,968)	(108,552)
Proceeds —			
Capital contributions	**146,356**	1,487	(662)
Senior notes	**—**	300,000	—
Other long-term debt	**10,253**	23,583	5,470
Redemptions — Other long-term debt	**(9,513)**	(9,284)	(2,450)
Distributions to noncontrolling interests	**(1,089)**	(506)	—
Capital contributions from noncontrolling interests	**7,531**	17,328	3,400
Payment of common stock dividends	**(131,120)**	(129,120)	(127,000)
Other financing activities	**(185)**	(746)	769
Net cash provided from (used for) financing activities	**217,150**	131,774	(229,025)
Net Change in Cash and Cash Equivalents	**5,862**	40,152	11,649
Cash and Cash Equivalents at Beginning of Year	**68,744**	28,592	16,943
Cash and Cash Equivalents at End of Year	**$ 74,606**	$ 68,744	$ 28,592
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $(113), $9,178 and $19,092 capitalized, respectively)	**$ 85,168**	$ 60,396	$ 50,248
Income taxes (net of refunds and investment tax credits)	**(219,641)**	(226,179)	(175,269)
Noncash transactions —			
Accrued property additions at year-end	**852**	5,567	11,203
Acquisitions	**228,964**	—	—
Capital contributions from noncontrolling interests	**220,734**	—	—

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2014 and 2013
Southern Power Company and Subsidiary Companies 2014 Annual Report

Assets	2014	2013
		(in thousands)
Current Assets:		
Cash and cash equivalents	$ 74,606	$ 68,744
Receivables —		
Customer accounts receivable	76,608	73,497
Other accounts receivable	14,707	3,983
Affiliated companies	34,223	38,391
Fossil fuel stock, at average cost	21,755	19,178
Materials and supplies, at average cost	57,843	54,780
Prepaid income taxes	19,239	54,523
Deferred income taxes, current	305,814	209
Other prepaid expenses	17,301	20,946
Assets from risk management activities	5,297	182
Total current assets	627,393	334,433
Property, Plant, and Equipment:		
In service	5,656,974	4,696,134
Less accumulated provision for depreciation	1,034,610	871,963
Plant in service, net of depreciation	4,622,364	3,824,171
Construction work in progress	10,511	9,843
Total property, plant, and equipment	4,632,875	3,834,014
Other Property and Investments:		
Goodwill	1,839	1,839
Other intangible assets, net of amortization of $8,279 and $5,614 at December 31, 2014 and December 31, 2013, respectively	47,091	43,505
Total other property and investments	48,930	45,344
Deferred Charges and Other Assets:		
Prepaid long-term service agreements	123,573	141,851
Other deferred charges and assets — affiliated	5,492	4,605
Other deferred charges and assets — non-affiliated	111,239	68,853
Total deferred charges and other assets	240,304	215,309
Total Assets	$ 5,549,502	$ 4,429,100

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2014 and 2013
Southern Power Company and Subsidiary Companies 2014 Annual Report

Liabilities and Stockholders' Equity	2014	2013
		(in thousands)
Current Liabilities:		
Securities due within one year	$ 525,295	$ 599
Notes Payable	194,917	—
Accounts payable —		
Affiliated	78,279	56,661
Other	30,037	20,747
Accrued taxes —		
Accrued income taxes	71,700	161
Other accrued taxes	2,983	2,662
Accrued interest	29,518	28,352
Other current liabilities	14,761	18,492
Total current liabilities	947,490	127,674
Long-Term Debt:		
Senior notes —		
4.875% due 2015	—	525,000
6.375% due 2036	200,000	200,000
5.15% due 2041	575,000	575,000
5.25% due 2043	300,000	300,000
Other long-term notes (3.25% due 2032-2034)	18,775	17,787
Unamortized debt premium	2,378	2,467
Unamortized debt discount	(813)	(1,013)
Long-term debt	1,095,340	1,619,241
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	862,795	724,390
Investment tax credits	600,519	340,269
Deferred capacity revenues — affiliated	15,279	15,279
Other deferred credits and liabilities — affiliated	604	1,621
Other deferred credits and liabilities — non-affiliated	16,890	7,896
Total deferred credits and other liabilities	1,496,087	1,089,455
Total Liabilities	3,538,917	2,836,370
Redeemable Noncontrolling Interest	39,241	28,778
Common Stockholder's Equity:		
Common stock, par value $0.01 per share —		
Authorized — 1,000,000 shares		
Outstanding — 1,000 shares	—	—
Paid-in capital	1,175,392	1,029,035
Retained earnings	573,178	531,998
Accumulated other comprehensive income	3,286	2,919
Total common stockholder's equity	1,751,856	1,563,952
Noncontrolling Interest	219,488	—
Total Stockholders' Equity	1,971,344	1,563,952
Total Liabilities and Stockholders' Equity	$ 5,549,502	$ 4,429,100
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, 2014, 2013, and 2012
Southern Power Company and Subsidiary Companies 2014 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholder's Equity	Noncontrolling Interest	Total
				(in thousands)				
Balance at December 31, 2011	1	$ —	$1,028,210	$ 447,301	$ (6,829)	$ 1,468,682	$ —	$ 1,468,682
Net income attributable to Southern Power Company	—	—	—	175,285	—	175,285	—	175,285
Capital contributions from parent company	—	—	(662)	—	—	(662)	—	(662
Other comprehensive income	—	—	—	—	6,053	6,053	—	6,053
Cash dividends on common stock	—	—	—	(127,000)	—	(127,000)	—	(127,000
Other	—	—	—	(1)	—	(1)	—	(1
Balance at December 31, 2012	1	—	1,027,548	495,585	(776)	1,522,357	—	1,522,357
Net income attributable to Southern Power Company	—	—	—	165,533	—	165,533	—	165,533
Capital contributions from parent company	—	—	1,487	—	—	1,487	—	1,487
Other comprehensive income	—	—	—	—	3,695	3,695	—	3,695
Cash dividends on common stock	—	—	—	(129,120)	—	(129,120)	—	(129,120
Balance at December 31, 2013	1	—	1,029,035	531,998	2,919	1,563,952	—	1,563,952
Net income attributable to Southern Power Company	—	—	—	172,300	—	172,300	—	172,300
Capital contributions from parent company	—	—	146,357	—	—	146,357	—	146,357
Other comprehensive income	—	—	—	—	367	367	—	367
Cash dividends on common stock	—	—	—	(131,120)	—	(131,120)	—	(131,120
Capital contributions from noncontrolling interest	—	—	—	—	—	—	220,734	220,734
Net loss attributable to noncontrolling interest	—	—	—	—	—	—	(1,246)	(1,246
Balance at December 31, 2014	1	$ —	$1,175,392	$ 573,178	$ 3,286	$ 1,751,856	$ 219,488	$ 1,971,344

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

Index to the Notes to Financial Statements

Note		Page
1	Summary of Significant Accounting Polices	II-469
2	Acquisitions	II-473
3	Contingencies and Regulatory Matters	II-475
4	Joint Ownership Agreements	II-475
5	Income Taxes	II-475
6	Financing	II-478
7	Commitments	II-479
8	Fair Value Measurements	II-480
9	Derivatives	II-482
10	Noncontrolling Interest	II-484
11	Quarterly Financial Information (Unaudited)	II-485

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Southern Power Company is a wholly-owned subsidiary of The Southern Company (Southern Company), which is also the parent company of four traditional operating companies, SCS, SouthernLINC Wireless, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, and other direct and indirect subsidiaries. The traditional 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. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants.

Southern Power Company and certain of its generation subsidiaries are subject to regulation by the FERC. The Company follows GAAP. 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. This includes an adjustment to the presentation of prepaid long-term service agreements (LTSA) to present amounts as noncurrent assets on the consolidated balance sheets. Prior period amounts recorded within other current assets have been reclassified to conform to the current presentation. See "Long-Term Service Agreements" herein for additional information.

The financial statements include the accounts of Southern Power Company and its wholly-owned subsidiaries, Southern Company – Florida, LLC, Oleander Power Project, LP, and Nacogdoches Power, LLC, which own, operate, and maintain the Company's ownership interests in Plants Stanton Unit A, Oleander, and Nacogdoches, respectively. The financial statements also include the accounts of Southern Power Company's wholly-owned subsidiaries, SRE and SRP. SRE and SRP were formed to construct, acquire, own, and manage renewable generation assets and sell electricity at market-based prices in the wholesale market. Through STR, a jointly-owned subsidiary owned 90% by SRE and 10% by TRE, SRE and its subsidiaries own, operate, and maintain Plants Adobe, Apex, Campo Verde, Cimarron, Granville, Macho Springs, and Spectrum. Through SG2 Holdings, a jointly-owned subsidiary owned 51% by SRP and 49% by First Solar, SRP owns, operates, and maintains Plant Imperial Valley. All intercompany accounts and transactions have been eliminated in consolidation.

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

Affiliate Transactions

Southern Power 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 amounted to approximately $125.9 million in 2014, $117.6 million in 2013, and $125.4 million in 2012. Of these costs, approximately $124.8 million in 2014, $114.3 million in 2013, and $107.7 million in 2012 were other operations and maintenance expenses; the remainder was recorded to plant in service. 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 several agreements with SCS for transmission services. Transmission purchased from affiliates totaled $6.8 million in 2014, $8.3 million in 2013, and $6.6 million in 2012. All charges were billed to the Company based on the Southern Company Open Access Transmission Tariff as filed with the FERC.

Total billings for all PPAs with affiliates were $156.4 million, $148.4 million, and $159.9 million in 2014, 2013, and 2012, respectively. Deferred amounts outstanding as of December 31 are included in the balance sheet as follows:

	2014	2013
	(in millions)	
Other deferred charges and assets - affiliated	$ 2.9	$ 1.9
Other current liabilities	—	(4.2)
Deferred capacity revenues - affiliated	(15.3)	(15.3)
Total deferred amounts outstanding	$ (12.4)	$ (17.6)

Revenue recognized under affiliate PPAs accounted for as operating leases totaled $74.8 million, $69.0 million, and $76.2 million in 2014, 2013, and 2012, respectively. The Company and the traditional 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 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. The Company accounts for business acquisitions from non-affiliates as business combinations. Accordingly, the Company includes these operations in the 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 in accordance with GAAP 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.

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.

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 further information.

Energy revenues and other contingent revenues are recognized in the period the energy is delivered or the service is rendered. All revenues under solar PPAs are accounted for as contingent revenues and recognized as services are performed. Transmission revenues and other fees are recognized as earned as other operating revenues. Revenues are recorded on a gross basis for all full requirements PPAs. 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:

	2014	2013	2012
FPL	10.1%	11.8%	12.8%
Georgia Power	9.7%	10.7%	12.5%
Duke Energy Corporation	9.1%	10.3%	5.9%

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 the American Recovery and Reinvestment Act of 2009 (ARRA), and the American Taxpayer Relief Act of 2012 (ATRA), certain projects are eligible for federal ITCs. The credits are recorded as a deferred credit and are amortized to income tax expense over the life of the asset. Credits amortized in this manner amounted to $11.4 million, $5.5 million, and $2.6 million in 2014, 2013, and 2012, respectively. Furthermore, the tax basis of the asset is reduced by 50% of the credits 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. Federal and state ITCs available to reduce income taxes payable were not fully utilized during the year and will be carried forward and utilized in future years. See Note 5 under "Effective Tax Rate" for additional information.

In accordance with accounting standards related to the uncertainty in income taxes, 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

The Company's depreciable property, plant, and equipment consists entirely of generation assets.

Property, plant, and equipment is stated at original cost. Original cost includes: materials, direct labor incurred by contractors and affiliated companies, minor items of property, 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.

Depreciation

Beginning in 2014, the Company changed to component depreciation, where the depreciation of the original cost of assets is computed principally by the straight-line method over the estimated useful lives of assets as determined by management. Certain generation assets are now 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 power plants, which have estimated useful lives ranging from 35 to 45 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. The book value of plant-in-service as of December 31, 2014 that is depreciated on a units-of-production basis was approximately $470.2 million.

When property subject to depreciation is retired or otherwise disposed of in the normal course of business, the applicable cost and accumulated depreciation is removed from the accounts and a gain or loss is recognized. For other property dispositions, the applicable cost and accumulated depreciation is removed from the balance sheet accounts and a gain or loss is recognized.

Prior to 2014, the Company computed depreciation of the original cost of assets under the straight-line method and applied a composite depreciation rate based on the assets' estimated useful lives as determined by management.

Long-Term Service Agreements

The Company has entered into LTSAs for the purpose of securing maintenance support for substantially all of its generating facilities. The LTSAs cover all planned inspections on the covered equipment, which generally includes the cost of all labor and materials. The LTSAs also obligate the counterparties to cover the costs of unplanned maintenance on the covered equipment subject to limits and scope specified in each contract.

Payments made under the LTSAs prior to the performance of any planned inspections or unplanned capital maintenance are recorded as a prepayment in noncurrent assets on the balance sheets and are recorded as payments pursuant to LTSAs in the statements of cash flows. All work performed is capitalized or charged to expense as appropriate based on the nature of the work when performed; therefore, these charges are non-cash and are not reflected in 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 of acquired PPAs that are amortized over the term of the PPA and goodwill resulting from acquisitions. The average term of these PPAs is 20 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. 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.

The amortization expense for the acquired PPAs for the years ended December 31, 2014, 2013, and 2012 was $2.5 million, $2.5 million, and $1.7 million, respectively, and the amortization for future periods is as follows:

	Amortization Expense
	(in millions)
2015	$ 2.5
2016	2.4
2017	2.5
2018	2.5
2019	2.5
2020 and beyond	28.5
Total	$ 40.9

Emission Reduction Credits

The Company has acquired emission reduction credits necessary for future unspecified construction in areas designated by the EPA as non-attainment areas for nitrogen oxide or volatile organic compound emissions. These credits are reflected on the balance sheets at historical cost. The cost of emission reduction offsets to be surrendered are generally transferred to CWIP upon commencement of construction. The total emission reduction credits were $11.0 million at December 31, 2014 and 2013.

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 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 cost of oil, natural gas, biomass, and emissions allowances. The Company maintains oil inventory for use at several 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, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (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. See Note 9 for additional information regarding derivatives. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2014.

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

2014

Adobe Solar, LLC

On April 17, 2014, the Company and TRE, through STR, a jointly-owned subsidiary owned 90% by the Company, acquired all of the outstanding membership interests of Adobe from Sun Edison, LLC, the original developer of the project. Adobe constructed and owns an approximately 20-MW solar generating facility in Kern County, California. The solar facility began commercial operation on May 21, 2014 and the entire output of the plant is contracted under a 20-year PPA with SCE. The acquisition was in accordance with the Company's overall growth strategy.

The Company's acquisition of Adobe included cash consideration of approximately $96.2 million, which included TRE's 10% equity contribution. The fair values of the assets, liabilities, and intangibles acquired were recorded as follows: $83.5 million to property, plant, and equipment, $14.5 million to prepayment related to transmission services, and $6.3 million to PPA intangible, resulting in a $5.2 million bargain purchase gain with a $2.9 million deferred tax liability. The bargain purchase gain is included in other income (expense), net in the Company's Statements of Income herein. Acquisition-related costs were expensed as incurred and were not material.

Macho Springs Solar, LLC

On May 22, 2014, the Company and TRE, through STR, acquired all of the outstanding membership interests of Macho Springs from First Solar Development, LLC, the original developer of the project. Macho Springs constructed and owns an approximately 50-MW solar photovoltaic facility in Luna County, New Mexico. The solar facility began commercial operation on May 23, 2014 and the entire output of the plant is contracted under a 20-year PPA with EPE. The acquisition was in accordance with the Company's overall growth strategy.

The Company's acquisition of Macho Springs included cash consideration of approximately $130.0 million, which included TRE's 10% equity contribution. The fair values of the assets acquired were recorded as follows: $128.0 million to property, plant, and equipment, $1.0 million to prepaid property taxes, and $1.0 million to prepayment related to transmission services. The acquisition did not include any contingent consideration. Acquisition-related costs were expensed as incurred and were not material.

SG2 Imperial Valley, LLC

On October 22, 2014, the Company, through its subsidiaries SRP and SG2 Holdings, acquired all of the outstanding membership interests of Imperial Valley from a wholly-owned subsidiary of First Solar, the developer of the project. Imperial Valley constructed and owns an approximately 150-MW solar photovoltaic facility in Southern California. The solar facility began commercial operation on November 26, 2014 and at that time a subsidiary of First Solar was admitted as a minority member of SG2 Holdings. The entire output of the plant is contracted under a 25-year PPA with San Diego Gas & Electric Company, a subsidiary of Sempra Energy (SDG&E). The acquisition was in accordance with the Company's overall growth strategy.

In connection with this acquisition, SG2 Holdings made an aggregate payment of approximately $127.9 million to a subsidiary of First Solar and became obligated to pay additional contingent consideration of approximately $599.3 million upon completion of the facility (representing the amount due to an affiliate of First Solar under the construction contract for Imperial Valley). When substantial completion was achieved on November 26, 2014, a subsidiary of First Solar was admitted as a minority member of SG2 Holdings. The members of SG2 Holdings made additional agreed upon capital contributions totaling $593.3 million to SG2 Holdings that were used to pay the contingent consideration due, leaving $6.0 million of contingent consideration payable upon final acceptance of the facility. As a result of these capital contributions, the aggregate purchase price payable by the Company for the acquisition of Imperial Valley was approximately $504.7 million in addition to the $222.5 million noncash contribution by the minority member. Following these capital contributions, the Company indirectly owns 100% of the class A membership interests of SG2 Holdings and is entitled to 51% of all cash distributions from SG2 Holdings, and First Solar indirectly owns 100% of the class B membership interests of SG2 Holdings and is entitled to 49% of all cash distributions from SG2 Holdings. In addition, the Company is entitled to substantially all of the federal tax benefits with respect to this transaction. As of December 31, 2014, the fair values of the assets acquired were recorded as follows: $707.5 million to property, plant, and equipment and $19.7 million to prepayment related to transmission services; however, the allocation of the purchase price to individual assets has not been finalized. Acquisition-related costs were expensed as incurred and were not material.

2013

Campo Verde Solar, LLC

In April 2013, the Company and TRE, through STR, acquired all of the outstanding membership interests of Campo Verde from First Solar, the developer of the project. Campo Verde constructed and owns an approximately 139-MW solar photovoltaic facility in Southern California. The solar facility began commercial operation in October 2013 and the entire output of the plant is contracted under a 20-year PPA with SDG&E. The asset acquisition was in accordance with the Company's overall growth strategy.

The Company's acquisition of Campo Verde included cash consideration of $136.6 million, which included TRE's 10% equity contribution. The fair value of the assets acquired was allocated entirely to property, plant, and equipment. The acquisition did not include any contingent consideration and due diligence costs were expensed as incurred and were not material. Under an engineering, procurement, and construction agreement, an additional $355.5 million was paid to a subsidiary of First Solar for construction of the solar facility.

Subsequent Events

Decatur County Solar Projects

On February 19, 2015, the Company acquired all of the outstanding membership interests of Decatur Parkway Solar Project, LLC and Decatur County Solar Project, LLC from TradeWind Energy, Inc. as part of the Company's plans to build two solar photovoltaic facilities; the Decatur Parkway Solar Project and the Decatur County Solar Project. These two projects, approximately 80-MW and 19-MW, respectively, will be constructed on separate sites in Decatur County, Georgia. The construction of the Decatur Parkway Solar Project commenced in February 2015 while the construction of the Decatur County Solar Project is expected to commence in June 2015. Both projects are expected to begin commercial operation in late 2015, and the entire output of each project is contracted to Georgia Power. The entire output of the Decatur Parkway Solar Project is contracted under a 25-year PPA with Georgia Power and the entire output of the Decatur County Solar Project is contracted under a separate 20-year PPA with Georgia Power. The total estimated cost of the facilities is expected to be between $200 million and $220 million, which includes the acquisition price for all of the outstanding membership interests of Decatur Parkway Solar Project, LLC and Decatur County Solar Project, LLC from TradeWind Energy, Inc. The acquisition is in accordance with the Company's overall growth strategy.

Kay County Wind Facility

On February 24, 2015, the Company, through its wholly-owned subsidiary SRE, entered into a purchase agreement with Kay Wind Holdings, LLC, a wholly-owned subsidiary of Apex Clean Energy Holdings, LLC, the developer of the project, to acquire all of the outstanding membership interests of Kay Wind. Kay Wind is constructing an approximately 299-MW wind facility in Kay County, Oklahoma. The wind facility is expected to begin commercial operation in late 2015. The entire output of the facility is contracted under separate 20-year PPAs with Westar Energy, Inc. and Grand River Dam Authority. The acquisition is in accordance with the Company's overall growth strategy.

The Company's acquisition of Kay Wind is expected to close in the fourth quarter 2015 and the purchase price is expected to be approximately $492 million, with potential purchase price adjustments based on performance testing. The completion of the acquisition is subject to Kay Wind achieving certain financing, construction, and project milestones, and various customary conditions to closing. The ultimate outcome of this matter 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.

4. JOINT OWNERSHIP AGREEMENTS

The Company is a 65% owner of Plant Stanton A, a combined-cycle project unit with a nameplate capacity of 659 MWs. The unit is co-owned by the Orlando Utilities Commission (28%), Florida Municipal Power Agency (3.5%), and 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, 2014, $156.5 million was recorded in plant in service with associated accumulated depreciation of $46.6 million. These amounts represent the Company's share of the 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 statements of income.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. In addition, the Company files separate company income tax returns for the States of Florida, New Mexico, South Carolina, and Tennessee. Unitary income tax returns are filed for the States of California, North Carolina, and Texas. 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:

	2014	2013	2012
		(in millions)	
Federal —			
Current	**$ 178.6**	$ (120.2)	$ (133.1)
Deferred	**(166.0)**	158.7	210.4
	12.6	38.5	77.3
State —			
Current	**(13.8)**	(5.2)	(3.0)
Deferred	**(2.0)**	12.6	18.3
	(15.8)	7.4	15.3
Total	**$ (3.2)**	$ 45.9	$ 92.6

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:

	2014	2013
		(in millions)
Deferred tax liabilities —		
Accelerated depreciation and other property basis differences	**$ 1,006.5**	$ 829.5
Basis difference on asset transfers	**2.6**	2.8
Levelized capacity revenues	**17.1**	11.2
Other	**5.7**	0.9
Total	**1,031.9**	844.4
Deferred tax assets —		
Federal effect of state deferred taxes	**28.9**	29.7
Net basis difference on federal ITCs	**101.5**	58.0
Alternative minimum tax carryforward	**15.0**	1.1
Unrealized tax credits	**305.2**	—
Unrealized loss on interest rate swaps	**6.1**	11.2
Levelized capacity revenues	**4.9**	6.0
Deferred state tax assets	**14.5**	17.0
Other	**4.1**	4.7
Total	**480.2**	127.7
Valuation Allowance	**(7.5)**	(7.5)
Net deferred income tax assets	**472.7**	120.2
Total deferred tax liabilities, net	**559.2**	724.2
Portion included in current assets/(liabilities), net	**303.6**	0.2
Accumulated deferred income taxes	**$ 862.8**	$ 724.4

Deferred tax liabilities are the result of property related timing differences.

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

Deferred tax assets consist primarily of timing differences related to net basis differences on federal ITCs and the carryforward of unrealized federal ITCs.

At December 31, 2014 and December 31, 2013, the Company had state net operating loss (NOL) carryforwards of $246.6 million and $240.8 million, respectively. The NOL carryforwards resulted in deferred tax assets of $9.4 million as of December 31, 2014 and $11.0 million as of December 31, 2013. The Company has established a valuation allowance due to the remote likelihood that the full tax benefits will be realized. During 2014, the estimated amount of NOL utilization decreased resulting in a $15.1 million increase in the valuation allowance. The increase in income tax expense resulting from the higher valuation allowance was offset by the net income impact of a decrease in the deferred tax balance due to a reduction in the state's statutory tax rate.

Of the NOL balance at December 31, 2014, approximately $87.0 million will expire in 2015 and $40.0 million will expire in 2017.

Effective Tax Rate

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

	2014	2013	2012
Federal statutory rate	**35.0 %**	35.0%	35.0%
State income tax, net of federal deduction	**(6.0)**	2.2	3.7
Amortization of ITC	**(4.3)**	(1.7)	(1.0)
ITC basis difference	**(27.7)**	(14.5)	(2.6)
Other	**1.1**	0.3	(0.6)
Effective income tax rate	**(1.9)%**	21.3%	34.5%

The Company's effective tax rate decreased in 2014 primarily due to increased benefits from federal ITCs related to Plants Adobe, Macho Springs, and Imperial Valley. The Company's effective tax rate decreased in 2013 primarily due to tax benefits from federal ITCs related to Plants Campo Verde and Spectrum.

In 2009, President Obama signed into law the ARRA. Major tax incentives in the ARRA included renewable energy incentives. The ATRA retroactively extended several renewable energy incentives through 2013, including extending federal ITCs for biomass projects which began construction before January 1, 2014.

The Company received cash related to federal ITCs under the renewable energy initiatives of $73.5 million in tax year 2014, $158.1 million in tax year 2013, and $45.0 million in tax year 2012. The tax benefit of the related basis difference reduced income tax expense by $47.5 million in 2014, $31.3 million in 2013, and $7.8 million in 2012.

See Note 1 under "Income and Other Taxes" for additional information.

Unrecognized Tax Benefits

Changes during the year in unrecognized tax benefits were as follows:

	2014	2013	2012
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 1.5**	$ 2.9	$ 2.6
Tax positions increase from current periods	**4.7**	1.6	0.7
Tax positions decrease from prior periods	**(1.5)**	(3.0)	(0.2)
Reductions due to settlements	**—**	—	(0.2)
Balance at end of year	**$ 4.7**	$ 1.5	$ 2.9

The increase in tax positions from current periods for 2014 and 2013 and the decrease from prior periods in 2014 relates to federal ITCs. The decrease in tax positions from prior periods for 2013 relates to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information.

The impact on the Company's effective tax rate, if recognized, is as follows:

	2014	2013	2012
		(in millions)	
Tax positions impacting the effective tax rate	**$4.7**	$1.5	$0.3
Tax positions not impacting the effective tax rate	—	—	2.6
Balance of unrecognized tax benefits	**$4.7**	$1.5	$2.9

The tax positions impacting the effective tax rate for 2014 and 2013 relate to federal ITCs. The tax positions not impacting the effective tax rate for 2012 related to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

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 federal income tax return and has received a partial acceptance letter from the IRS; however, the IRS has not finalized its audit. 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 2010.

Tax Method of Accounting for Repairs

In 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. Additionally, in April 2013, the IRS issued Revenue Procedure 2013-24, which provides guidance for taxpayers related to the deductibility of repair costs associated with generation assets. Based on a review of the regulations, Southern Company incorporated provisions related to repair costs for generation assets into its consolidated 2012 federal income tax return and reversed all related unrecognized tax positions. In September 2013, the IRS issued Treasury Decision 9636, "Guidance Regarding Deduction and Capitalization of Expenditures Related to Tangible Property," which are final tangible property regulations applicable to taxable years beginning on or after January 1, 2014. Southern Company continues to review this guidance; however, these regulations are not expected to have a material impact on the Company's financial statements.

6. FINANCING

Securities Due Within One Year

At December 31, 2014, the Company had $525.0 million of senior notes due within one year. In addition, at December 31, 2014, the Company classified as due within one year approximately $0.3 million of long-term debt payable to TRE that is expected to be repaid in 2015. At December 31, 2013, the Company classified approximately $0.6 million of long-term debt payable to TRE as due within one year.

There are no additional scheduled maturities of long-term debt through 2019.

Other Long-Term Notes

During 2014, the Company prepaid $9.5 million of long-term debt payable to TRE and issued $0.1 million due June 15, 2032, $0.8 million due April 30, 2033, $3.9 million due April 30, 2034, and $5.4 million due May 31, 2034 under promissory notes payable to TRE related to the financing of Apex, Campo Verde, Adobe, and Macho Springs, respectively. At December 31, 2014, and 2013, the Company had $18.8 million and $17.8 million, respectively, of long-term debt payable to TRE.

Senior Notes

During 2013, Southern Power Company issued $300 million aggregate principal amount of its Series 2013A 5.25% Senior Notes due July 15, 2043. The net proceeds from the sale of the Series 2013A Senior Notes were used to repay a portion of its outstanding short-term indebtedness and for other general corporate purposes, including the Company's continuous construction program.

At December 31, 2014 and 2013, Southern Power Company had $1.6 billion of senior notes outstanding, which included senior notes due within one year.

Bank Credit Arrangements

In February 2013, Southern Power Company amended its $500 million committed credit facility (Facility), which extended the maturity date from 2016 to 2018. As of December 31, 2014, the total amount available under the Facility was $488 million. There were no borrowings outstanding under the Facility at December 31, 2013. The Facility does not contain a material adverse change clause at the time of borrowing. Subject to applicable market conditions, Southern Power Company plans to renew the Facility prior to its expiration.

Southern Power 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%. At December 31, 2014, the Company was in compliance with its debt limits.

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.

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes. Commercial paper is included in notes payable in the balance sheets.

Details of short-term borrowings are shown below. The Company had no short-term borrowings in 2013.

	Commercial Paper at the End of the Period	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2014	$ 195	0.4%

Dividend Restrictions

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

The indenture related to certain series of Southern Power Company's senior notes also contains certain limitations on the payment of common stock dividends. No dividends may be paid unless, as of the end of any calendar quarter, the Company's projected cash flows from fixed priced capacity PPAs are at least 80% of total projected cash flows for the next 12 months or the Company's debt to capitalization ratio is no greater than 60%. At December 31, 2014, Southern Power Company was in compliance with these ratios and had no other restrictions on its ability to pay dividends.

7. COMMITMENTS

Fuel Agreements

SCS, as agent for the Company and the traditional 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 balance sheets. In 2014, 2013, and 2012, the Company incurred fuel expense of $596.3 million, $473.8 million, and $426.3 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 operating companies. Under these agreements, each of the traditional operating companies and the Company may be jointly and severally liable. Southern Company has entered into keep-well agreements with each of the traditional 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 $4.0 million, $1.9 million, and $0.8 million for 2014, 2013, and 2012, respectively. These amounts include contingent rent expense related to the Plant Stanton Unit A land lease based on escalation in the Consumer Price Index for All Urban Consumers. The Company includes 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, 2014, estimated minimum lease payments under operating leases were $4.5 million in 2015, $4.5 million in 2016, $4.6 million in 2017, $4.6 million in 2018, $4.7 million in 2019, and $157.2 million in 2020 and thereafter. The majority of the committed future expenditures are land leases at solar facilities.

Redeemable Noncontrolling Interest

Pursuant to an agreement with TRE, on or after November 25, 2015, or earlier in the event of the death of the controlling member of TRE, TRE may require the Company to purchase its noncontrolling interest in STR at fair market value.

See Note 10 for additional information.

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, 2014, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 5.5	$ —	$ 5.5
Cash equivalents	18.0	—	—	18.0
Total	$ 18.0	$ 5.5	$ —	$ 23.5
Liabilities:				
Energy-related derivatives	$ —	$ 3.6	$ —	$ 3.6

As of December 31, 2013, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2013:	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	$ —	$ 0.6	$ —	$ 0.6
Cash equivalents	68.0	—	—	68.0
Total	$ 68.0	$ 0.6	$ —	$ 68.6
Liabilities:				
Energy-related derivatives	$ —	$ 0.6	$ —	$ 0.6

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. See Note 9 for additional information on how these derivatives are used.

As of December 31, 2014 and 2013, the fair value measurements of investments calculated at net asset value per share (or its equivalent), 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, 2014:				
Cash equivalents:				
Money market funds	$ 18.0	None	Daily	Not applicable
As of December 31, 2013:				
Cash equivalents:				
Money market funds	$ 68.0	None	Daily	Not applicable

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2014 and 2013, 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:		
2014	**$ 1,621**	**$ 1,785**
2013	$ 1,620	$ 1,660

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.

9. 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 gross basis. See Note 8 herein 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. The Company has limited exposure to market volatility in commodity fuel prices and prices of electricity 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.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price or heat rate contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in 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 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, 2014, the net volume of energy-related derivative contracts for natural gas positions totaled 3.4 million mmBtu, all of which expire by 2017, which is the longest non-hedge date. At December 31, 2014, the net volume of energy-related derivative contracts for power positions was immaterial. 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 1.0 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, 2015 are immaterial.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives from time to time 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, 2014, there were no interest rate derivatives outstanding.

The estimated pre-tax loss that will be reclassified from AOCI to interest expense for the 12-month period ending December 31, 2015 is $1.0 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2016.

Derivative Financial Statement Presentation and Amounts

At December 31, 2014 and 2013, the fair value of energy-related derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in millions)			*(in millions)*	
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Assets from risk management activities	**$ 5.3**	$ 0.2	Other current liabilities	**$ 3.5**	$ 0.6
	Other deferred charges and assets – non-affiliated	**0.2**	0.4	Other deferred credits and liabilities – non-affiliated	**0.1**	—
Total derivatives not designated as hedging instruments		**$ 5.5**	$ 0.6		**$ 3.6**	$ 0.6

The derivative contracts of the Company are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related and interest rate derivative contracts contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts at December 31, 2014 and 2013 are presented in the following tables. Interest rate derivatives presented in the tables above do not have amounts available for offset and are therefore excluded from the offsetting disclosure tables below.

	Fair Value			
Assets	**2014**	2013	**Liabilities**	**2014**	2013
	(in millions)			*(in millions)*	
Energy-related derivatives presented in the Balance Sheet [a]	**$ 5.5**	$ 0.6	Energy-related derivatives presented in the Balance Sheet [a]	**$ 3.6**	$ 0.6
Gross amounts not offset in the Balance Sheet [b]	**(0.1)**	(0.1)	Gross amounts not offset in the Balance Sheet [b]	**(0.1)**	(0.1)
Net energy-related derivative assets	**$ 5.4**	$ 0.5	**Net energy-related derivative liabilities**	**$ 3.5**	$ 0.5

(a) The Company does not offset fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.
(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

For the years ended December 31, 2014, 2013, and 2012, the pre-tax effects of energy-related derivatives and 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) Reclassified from AOCI into Income (Effective Portion)**			
		Amount		
Derivative Category	**Statements of Income Location**	**2014**	2013	2012
			(in millions)	
Energy-related derivatives	Depreciation and amortization	**$ 0.4**	$ 0.4	$ 0.4
Interest rate derivatives	Interest expense, net of amounts capitalized	**(0.9)**	(6.5)	(10.5)
Total		**$ (0.5)**	$ (6.1)	$ (10.1)

There was no material ineffectiveness recorded in earnings for any period presented.

For the Company's energy-related derivatives not designated as hedging instruments, a portion of the pre-tax realized and unrealized gains and losses is associated with hedging fuel price risk of certain PPA customers and has no impact on net income or on fuel expense as presented in the Company's statements of income. The pre-tax effects of energy-related derivatives not

designated as hedging instruments on the Company's statements of income were immaterial for the years ended December 31, 2014, 2013, and 2012. This third party hedging activity has been discontinued.

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, 2014, the amount of collateral posted with its derivative counterparties was immaterial.

At December 31, 2014, the fair value of derivative liabilities with contingent features was $1.5 million. However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $54.5 million, and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

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

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

10. NONCONTROLLING INTEREST

The following table details the components of redeemable noncontrolling interests for the years ended December 31:

	2014	2013	2012
		(in millions)	
Beginning balance	$ **28.8**	$ 8.1	$ 3.8
Net income attributable to redeemable noncontrolling interest	**4.0**	3.9	0.9
Distributions to redeemable noncontrolling interest	**(1.1)**	(0.5)	—
Capital contributions from redeemable noncontrolling interest	**7.5**	17.3	3.4
Ending balance	$ **39.2**	$ 28.8	$ 8.1

For the year ended December 31, 2014, net income included in the consolidated statements of changes in stockholders' equity is reconciled to net income presented in the consolidated statements of income as follows:

	2014
Net income attributable to Southern Power Company	$ **172.3**
Net loss attributable to noncontrolling interest	**(1.2)**
Net income attributable to redeemable noncontrolling interest	**4.0**
Net income	$ **175.1**

For the years ended December 31, 2013 and 2012, net income attributable to redeemable noncontrolling interest was $3.9 million and $0.9 million, respectively, and was included in "Other income (expense), net" in the consolidated statements of income.

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2014 and 2013 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income Attributable to Southern Power Company
		(in thousands)	
March 2014	**$ 350,854**	**$ 59,358**	**$ 33,471**
June 2014	**328,803**	**51,073**	**30,812**
September 2014	**435,256**	**104,710**	**63,631**
December 2014	**386,336**	**40,138**	**44,386**
March 2013	$ 302,947	$ 64,673	$ 29,192
June 2013	307,255	55,024	27,922
September 2013	364,767	116,497	85,153
December 2013	300,257	53,781	23,266

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

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2010-2014
Southern Power Company and Subsidiary Companies 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in thousands):					
Wholesale — non-affiliates	**$ 1,115,880**	$ 922,811	$ 753,653	$ 870,607	$ 752,772
Wholesale — affiliates	**382,523**	345,799	425,180	358,585	370,630
Total revenues from sales of electricity	**1,498,403**	1,268,610	1,178,833	1,229,192	1,123,402
Other revenues	**2,846**	6,616	7,215	6,769	6,939
Total	**$ 1,501,249**	$ 1,275,226	$ 1,186,048	$ 1,235,961	$ 1,130,341
Net Income Attributable to Southern Power Company (in thousands)	**$ 172,300**	$ 165,533	$ 175,285	$ 162,231	$ 131,309
Cash Dividends on Common Stock (in thousands)	**$ 131,120**	$ 129,120	$ 127,000	$ 91,200	$ 107,100
Return on Average Common Equity (percent)	**10.39**	10.73	11.72	11.88	10.68
Total Assets (in thousands)	**$ 5,549,502**	$ 4,429,100	$ 3,779,927	$ 3,580,977	$ 3,437,734
Gross Property Additions and Acquisitions (in thousands)	**$ 942,454**	$ 632,919	$ 240,692	$ 254,725	$ 404,644
Capitalization (in thousands):					
Common stock equity	**$ 1,751,856**	$ 1,563,952	$ 1,522,357	$ 1,468,682	$ 1,263,220
Redeemable noncontrolling interest	**39,241**	28,778	8,069	3,825	—
Noncontrolling interest	**219,488**	—	—	—	—
Long-term debt	**1,095,340**	1,619,241	1,306,099	1,302,758	1,302,619
Total (excluding amounts due within one year)	**$ 3,105,925**	$ 3,211,971	$ 2,836,525	$ 2,775,265	$ 2,565,839
Capitalization Ratios (percent):					
Common stock equity	**56.4**	48.7	53.7	52.9	49.2
Redeemable noncontrolling interest	**1.3**	0.9	0.3	0.1	—
Noncontrolling interest	**7.1**	—	—	—	—
Long-term debt	**35.2**	50.4	46.0	47.0	50.8
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Kilowatt-Hour Sales (in thousands):					
Wholesale — non-affiliates	**19,014,445**	15,110,616	15,636,986	16,089,875	13,294,455
Wholesale — affiliates	**11,193,530**	9,359,500	16,373,245	11,773,890	10,494,339
Total	**30,207,975**	24,470,116	32,010,231	27,863,765	23,788,794
Average Revenue Per Kilowatt-Hour (cents)	**4.96**	5.18	3.68	4.41	4.72
Plant Nameplate Capacity Ratings (year-end) (megawatts)*	**9,185**	8,924	8,764	7,908	7,908
Maximum Peak-Hour Demand (megawatts):					
Winter	**3,999**	2,685	3,018	3,255	3,295
Summer	**3,998**	3,271	3,641	3,589	3,543
Annual Load Factor (percent)	**51.8**	54.2	48.6	51.0	54.0
Plant Availability (percent)**	**91.8**	91.8	92.9	93.9	94.0
Source of Energy Supply (percent):					
Gas	**86.0**	88.5	91.0	89.2	88.8
Alternative (Solar and Biomass)	**2.9**	1.1	0.5	0.2	—
Purchased power —					
From non-affiliates	**6.4**	6.4	7.2	6.7	5.5
From affiliates	**4.7**	4.0	1.3	3.9	5.7
Total	**100.0**	100.0	100.0	100.0	100.0

* Plant nameplate capacity ratings include 100% of all solar facilities. When taking into consideration the Company's 90% equity interest in STR (which includes Plants Adobe, Apex, Campo Verde, Cimarron, Macho Springs and Spectrum) and 51% equity interest in SG2 Holdings (which includes Plant Imperial Valley), the Company's equity portion of total nameplate capacity for 2014 is 9,074 MW.

** Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

[This page intentionally left blank]

PART III

Items 10, 11, 12 (other than the information under "Code of Ethics" below in Item 10 and in paragraph (b) in Item 12), 13, and 14 for Southern Company are incorporated by reference to Southern Company's Definitive Proxy Statement relating to the 2015 Annual Meeting of Stockholders. 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 Discussion and Analysis," "Compensation and Management Succession Committee Report," "Compensation Committee Interlocks and Insider Participation," "Compensation Risk Assessment," "Director Compensation," "Director Deferred Compensation Plan," and "Director Compensation Table" for Item 11, "Stock Ownership Table" and "Equity Plan Compensation Information" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12 (other than the information under "Code of Ethics" below in Item 10 and in paragraph (b) in Item 12), 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 2015 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 Discussion and Analysis," "Compensation and Management Succession Committee Report," "Compensation Committee Interlocks and Insider Participation," "Compensation Risk Assessment," "Director Compensation," "Director Deferred Compensation Plan," and "Director Compensation Table" for Item 11, "Stock Ownership Table" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal 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 Southern Power are omitted pursuant to General Instruction I(2)(c) of Form 10-K. Item 14 for Southern Power is contained herein.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Identification of directors of Gulf Power **(1)**

S. W. Connally, Jr. President and Chief Executive Officer Age 45 Served as Director since 2012	**Julian B. MacQueen (2)** Age 64 Served as Director since 2013
Allan G. Bense (2) Age 63 Served as Director since 2010	**J. Mort O'Sullivan, III (2)** Age 63 Served as Director since 2010
Deborah H. Calder (2) Age 54 Served as Director since 2010	**Michael T. Rehwinkel (2)** Age 58 Served as Director since 2013
William C. Cramer, Jr. (2) Age 62 Served as Director since 2002	**Winston E. Scott (2)** Age 64 Served as Director since 2003

(1) *Ages listed are as of December 31, 2014.*

(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 24, 2014) 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. President and Chief Executive Officer Age 45 Served as Executive Officer since 2012	**Michael L. Burroughs** Vice President — Senior Production Officer Age 54 Served as Executive Officer since 2010
Jim R. Fletcher Vice President — External Affairs and Corporate Services Age 48 Served as Executive Officer since 2014	**Wendell E. Smith** Vice President — Power Delivery Age 49 Served as Executive Officer since 2014
Richard S. Teel Vice President and Chief Financial Officer Age 44 Served as Executive Officer since 2010	**Bentina C. Terry** Vice President — Customer Service and Sales Age 44 Served as Executive Officer since 2007

(1) *Ages listed are as of December 31, 2014.*

Each of the above is currently an executive officer of Gulf Power, serving a term until the next annual organizational 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 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. - President and Chief Executive Officer of Gulf Power since July 2012. Mr. Connally has also served as Chairman of Gulf Power's Board of Directors since July 2012. Mr. Connally previously served as Senior Vice President and Chief Production Officer of Georgia Power from July 2010 through June 2012 and Manager of Alabama Power's Plant Barry from August 2007 through July 2010.

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. Mr. Bense served as Vice Chair of Enterprise Florida, the economic development agency for the state, from January 2009 to January 2011. Mr. Bense is also a member of the board of directors of Capital City Bank Group, Inc.

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 4,000 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 23 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, Georgia, and Alabama. Mr. Cramer has been an authorized Chevrolet dealer for over 25 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. 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 Warren Averett O'Sullivan Creel division of Warren Averett, LLC, an accounting firm originally formed as O'Sullivan Patton Jacobi in 1981. 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.

Michael T. Rehwinkel - Executive Chairman of EVRAZ North America, a steel manufacturer, since July 2013. He previously served as Chief Executive Officer and President of EVRAZ North America from February 2010 to July 2013 and previously

held various executive positions at Georgia-Pacific Corporation. Mr. Rehwinkel is also Chairman of the American Iron and Steel Institute. Mr. Rehwinkel has more than 30 years of industrial business and leadership experience.

Winston E. Scott - Senior Vice President for External Relations and Economic Development, Florida Institute of Technology since March 2012. He previously served as Dean, College of Aeronautics, Florida Institute of Technology, Melbourne, Florida from August 2008 through March 2012. Mr. Scott is also a member of the board of directors of Environmental Tectonics Corporation. Mr. Scott's experience includes serving as a pilot in the U.S. Navy, an astronaut with the National Aeronautic and Space Administration, Executive Director of the Florida Space Authority, and Vice President of Jacobs Engineering.

EXECUTIVE OFFICERS

Michael L. Burroughs - Vice President and Senior Production Officer since August 2010. He previously served as Manager of Georgia Power's Plant Yates from September 2007 to July 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 and Regulatory Affairs Manager for Georgia Power from March 2006 to January 2011.

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, Transmission Construction Manager for Georgia Power from February 2011 to December 2011, and Distribution Manager for Georgia Power from March 2005 to February 2011.

Richard S. Teel - Vice President and Chief Financial Officer since August 2010. He previously served as Vice President and Chief Financial Officer of Southern Company Generation, a business unit of Southern Company, from January 2007 to July 2010.

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 Certain Control Persons. None.

Section 16(a) Beneficial Ownership Reporting Compliance. None.

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 Melissa K. Caen, 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 Melissa K. Caen, Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308.

Southern Company owns all of Gulf Power's outstanding common stock and Gulf Power has listed only debt securities on the NYSE. Accordingly, under the rules of the NYSE, Gulf Power is exempt from most of the NYSE's listing standards relating to corporate governance. In addition, 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 2014, as well as each of its other three most highly compensated executive officers serving at the end of the year.

S. W. Connally, Jr.	President and Chief Executive Officer
Richard S. Teel	Vice President and Chief Financial Officer
Michael L. Burroughs	Vice President
Jim R. Fletcher	Vice President
Bentina C. Terry	Vice President

Also described is the compensation of Gulf Power's former Vice President, P. Bernard Jacob, who retired from Gulf Power effective as of May 3, 2014. Collectively, these officers are referred to as the named executive officers.

Executive Summary

Performance and Pay

Performance-based pay represents a substantial portion of the total direct compensation paid or granted to the named executive officers for 2014.

	Salary ($)[1]	% of Total	Short-Term Performance Pay ($)[1]	% of Total	Long-Term Performance Pay ($)[1]	% of Total
S. W. Connally, Jr.	393,907	31%	339,302	27%	517,692	42%
R. S. Teel	252,110	45%	161,989	29%	152,101	26%
M. L. Burroughs	199,209	50%	121,801	30%	80,103	20%
J. R. Fletcher	224,547	49%	149,633	33%	84,480	18%
B. C. Terry	270,543	45%	173,833	29%	163,191	26%

(1) Salary is the actual amount paid in 2014, Short-Term Performance Pay is the actual amount earned in 2014 based on performance, and Long-Term Performance Pay is the value on the grant date of stock options and performance shares granted in 2014. See the Summary Compensation Table for the amounts of all elements of reportable compensation described in this CD&A. Information is provided for named executive officers serving at the end of 2014.

Gulf Power financial and operational and Southern Company earnings per share (EPS) goal results for 2014, as adjusted and further described in this CD&A, are shown below:

Financial: 100% of Target Operational: 149% of Target EPS: 176% of Target

Southern Company's annualized total shareholder return has been:

1-Year: 25.23% 3-Year: 6.67% 5-year: 13.22%

These levels of achievement resulted in payouts that were aligned with Gulf Power and Southern Company performance.

Compensation and Benefit Beliefs and Practices

The compensation and benefit 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;
- Motivate and 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 total shareholder return for Southern Company's stockholders. Therefore, short-term performance pay is based on achievement of Gulf Power's operational and financial performance goals, with one-third determined by operational performance, such as safety, reliability, and customer satisfaction; one-third determined by business unit financial performance; and one-third determined by Southern Company's EPS performance. Long-term performance pay is tied to Southern Company's stockholder value, with 40% of the target value awarded in Southern Company stock options, which reward stock price appreciation, and 60% awarded in performance shares, which reward Southern Company's total shareholder return performance relative to that of industry peers and stock price appreciation.

Key Governance and Pay Practices

- Annual pay risk assessment required by the Compensation Committee charter.
- Retention by the Compensation Committee of an independent compensation consultant, 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 ongoing perquisites with no income tax gross-ups for the 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.
- 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 uses information from others, principally Pay Governance. The Compensation Committee also relies on information from Southern Company's 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 2014 annual meeting of stockholders. In light of the significant support of Southern Company's stockholders (94% 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.

Executive Compensation Focus

The executive compensation program places significant focus on rewarding performance. The program is performance-based in several respects:

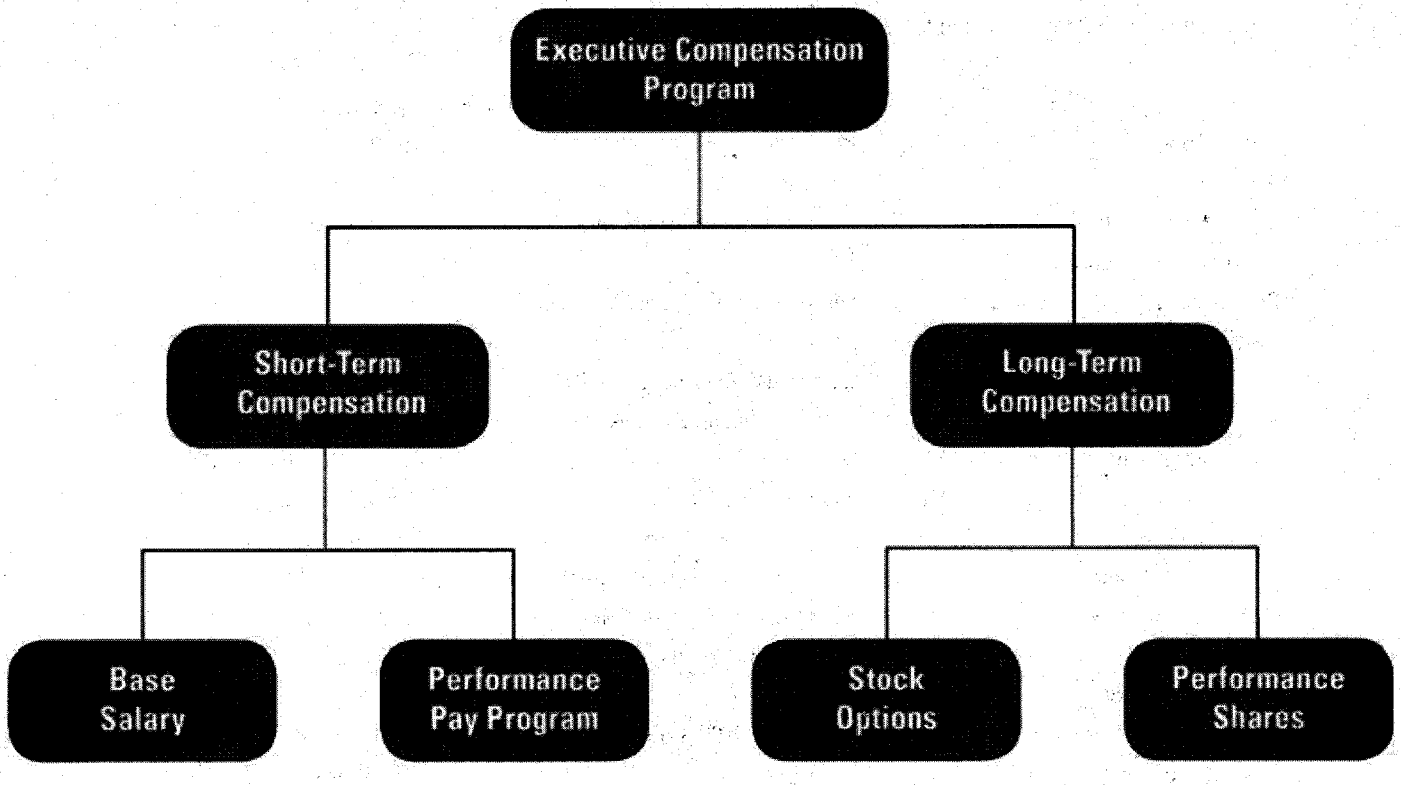
- Business unit financial and operational performance and Southern Company EPS, based on actual results compared to target performance levels established early in the year, determine the actual payouts under the short-term (annual) performance-based compensation program (Performance Pay Program).
- Southern Company Common Stock (Common Stock) price changes result in higher or lower ultimate values of stock options.
- Southern Company's total shareholder return compared to those of industry peers leads to higher or lower payouts under the Performance Share Program (performance shares).

In support of this performance-based pay philosophy, Gulf Power has no general employment contracts or guaranteed severance with the named executive officers, except upon a change in control.

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 more than 1,300 employees of Gulf Power. Stock options and performance shares were granted to over 125 employees of Gulf Power. These programs engage employees, which ultimately is good not only for them, but also for Gulf Power's customers and Southern Company's stockholders.

OVERVIEW OF EXECUTIVE COMPENSATION COMPONENTS

The primary components of the 2014 executive compensation program are shown below:



Gulf Power's executive compensation program consists of a combination of short-term and long-term components. Short-term compensation includes base salary and the Performance Pay Program. Long-term performance-based compensation includes stock options and performance shares. The performance-based compensation components are linked to Gulf Power's financial and operational performance, Common Stock performance, and Southern Company's total shareholder return. 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 motivates and rewards performance.

ESTABLISHING MARKET-BASED COMPENSATION LEVELS

Pay Governance develops and presents to the Compensation Committee a competitive market-based compensation level for the Gulf Power Chief Executive Officer. Southern Company's Human Resources staff develops competitive market-based compensation levels for the other Gulf Power named executive officers. The market-based compensation levels for both are developed from a size-appropriate energy services executive compensation survey database. The survey participants, listed below, are utilities with revenues of $1 billion or more. The Compensation Committee reviews the data and uses it in establishing market-based compensation levels for the named executive officers.

AGL Resources Inc.	Entergy Corporation	Pepco Holdings, Inc.
Allete, Inc.	EP Energy Corporation	Pinnacle West Capital Corporation
Alliant Energy Corporation	Eversource International	Portland General Electric Company
Ameren Corporation	Exelon Corporation	PPL Corporation
American Electric Power Company, Inc.	FirstEnergy Corp.	Public Service Enterprise Group Inc.
Areva Inc.	First Solar Inc.	PNM Resources Inc.
Atmos Energy Corporation	GDF SUEZ Energy North America, Inc.	Puget Energy, Inc.
Austin Energy	Iberdrola USA, Inc.	Salt River Project
Avista Corporation	Idaho Power Company	Santee Cooper
Bg US Services, Inc.	Integrys Energy Group, Inc.	SCANA Corporation
Black Hills Corporation	JEA	Sempra Energy
Boardwalk Pipeline Partners, L.P.	Kinder Morgan Energy Partners, L.P.	Southwest Gas Corporation
Calpine Corporation	Laclede Group, Inc.	Spectra Energy Corp.
CenterpPoint Energy, Inc.	LG&E and KU Energy LLC	TECO Energy, Inc.
Cleco Corporation	Lower Colorado River Authority	Tennessee Valley Authority
CMS Energy Corporation	MDU Resources Group, Inc.	The AES Corporation
Consolidated Edison, Inc.	National Grid USA	The Babcock & Wilcox Company
Dominion Resources, Inc.	Nebraska Public Power District	The Williams Companies, Inc.
DTE Energy Company	New Jersey Resources Corporation	TransCanada Corporation
Duke Energy Corporation	New York Power Authority	Tri-State Generation & Transmission Association, Inc.
Dynegy Inc.	NextEra Energy, Inc.	
Edison International	NiSource Inc.	UGI Corporation
ElectriCities of North Carolina	NorthWestern Corporation	UIL Holdings
Energen Corporation	NRG Energy, Inc.	UNS Energy Corporation
Energy Future Holdings Corp.	OGE Energy Corp.	Vectren Corporation
Energy Solutions, Inc.	Omaha Public Power District	Westar Energy, Inc.
Energy Transfer Partners, L.P.	Oncor Electric Delivery Company LLC	Wisconsin Energy Corporation
EnLink Midstream	Pacific Gas & Electric Company	Xcel Energy Inc.

Market data for the 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, annual performance-based compensation at a target performance level, and long-term performance-based compensation (stock options and performance shares) at a target value. 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 or annual or long-term performance-based compensation as a percentage of total target compensation opportunities, nor did amounts realized or realizable from prior compensation serve to increase or decrease 2014 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. The total target compensation opportunity was established in early 2014 for each named executive officer below:

	Salary ($)	Target Annual Performance-Based Compensation ($)	Target Long-Term Performance-Based Compensation ($)	Total Target Compensation Opportunity ($)
S. W. Connally, Jr.	398,242	238,945	517,692	1,154,879
R. S. Teel	253,504	114,077	152,101	519,682
M. L. Burroughs	200,331	80,133	80,103	360,567
J. R. Fletcher	211,255	84,502	84,480	380,237
P. B. Jacob	267,107	120,198	160,246	547,551
B. C. Terry	272,039	122,418	163,191	557,648

The salary levels shown above were not effective until March 2014. Therefore, the salary amounts reported in the Summary Compensation Table are different than the amounts shown above because that table reports actual amounts paid in 2014. The total target compensation opportunity amount shown for Mr. Jacob represents the full amount had he been employed the entire year by Gulf Power. However, the actual amounts Mr. Jacob received for salary and annual performance-based compensation were prorated based on the amount of time he was employed at Gulf Power in 2014. Additionally, the ultimate number of performance shares earned by Mr. Jacob will be prorated based on the time he was employed during the performance period. See the Summary Compensation Table and Grants of Plan-Based Awards in 2014 for more information on the actual compensation amounts Mr. Jacob received.

Mr. Fletcher was employed at Georgia Power as the Vice President of Governmental and Regulatory Affairs prior to his promotion to Vice President at Gulf Power on March 29, 2014. At that time, his base salary and target annual performance-based compensation were increased to $231,324 and $101,343, respectively.

For purposes of comparing the value of the compensation program to the market data, stock options are valued at $2.20 per option and performance shares at $37.54 per unit. These values represent risk-adjusted present values on the date of grant and are consistent with the methodologies used to develop the market data. The mix of stock options and performance shares granted was 40% and 60%, respectively, of the long-term value shown above.

In 2013, Pay Governance analyzed the level of actual payouts for 2012 performance under the annual Performance Pay Program made to the named executive officers relative to performance versus peer companies to provide a check on the goal-setting process, including goal levels and associated performance-based pay opportunities. The findings from the analysis were used in establishing performance goals and the associated range of payouts for goal achievement for 2014. That analysis was updated in 2014 by Pay Governance for 2013 performance, and those findings were used in establishing goals for 2015.

DESCRIPTION OF KEY COMPENSATION COMPONENTS

2014 Base Salary

Most employees, including all of the named executive officers, received base salary increases in 2014.

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 base salary levels established early in the year for the named executive officers were set within the applicable position level salary range and were recommended by the individual named executive officer's supervisor and approved by Southern Company's Chief Executive Officer. Mr. Connally's base salary increase was approved by the Compensation Committee.

2014 Performance-Based Compensation

This section describes performance-based compensation for 2014.

Achieving Operational and Financial Performance Goals — The Guiding Principle for Performance-Based Compensation

The Southern Company system's number one priority is to continue 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 2014, 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;
- Southern Company dividend growth;
- Long-term, risk-adjusted Southern Company total shareholder return;
- 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.

The Southern Company Chief Executive Officer, with the assistance of Southern Company's Human Resources staff, recommended to the Compensation Committee the program design and award amounts for senior management, including the named executive officers.

2014 Annual Performance-Based Pay Program

Annual Performance Pay Program Highlights

- Rewards achievement of annual performance goals:
  - Business unit net income
  - Business unit operational performance
  - Southern Company EPS
- Goals are weighted one-third each
- Performance results range from 0% to 200% of target, based on level of goal achievement

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. In setting goals for pay purposes, 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 operating companies, including Gulf Power, and Southern Power, the business unit financial performance goal is net income.

- **Business Unit Operational Goals: Varies by business unit**
  For Southern Company's traditional operating companies, including Gulf Power, operational goals are safety, customer satisfaction, plant availability, transmission and distribution system reliability, major projects (Georgia Power and Mississippi Power), and culture. 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. The EPS performance measure is applicable to all participants in the Performance Pay Program.

The Compensation Committee may make adjustments, both positive and negative, to goal achievement for purposes of determining payouts. For the financial goals, such adjustments typically include the impact of items considered non-recurring or outside of normal operations or not anticipated in the business plan when the financial goals were established and of sufficient magnitude to warrant recognition. As reported in Gulf Power's Annual Report on Form 10-K for the year ended December 31, 2013, the Compensation Committee did not follow its usual practice, and the charges taken in 2013 related to Mississippi Power's construction of the Kemper IGCC were not excluded from goal achievement results. Because the charges were not excluded, the payout levels for all employees, including the named executive officers, were reduced significantly in 2013. In 2014, Southern Company recorded pre-tax charges to earnings of $868 million ($536 million after-tax, or $0.59 per share) (2014 Kemper IGCC Charges) due to estimated probable losses relating to the Kemper IGCC. Additionally, Southern Company adjusted its 2014 net income by $17 million after-tax (or $0.02 per share) relating to the reversal of previously recognized revenues recorded in 2014 and 2013 and the recognition of carrying costs associated with the 2015 Mississippi Supreme Court decision that reversed the Mississippi PSC's March 2013 rate order associated with the Kemper IGCC (together with the 2014 Kemper IGCC Charges, 2014 Kemper IGCC Charges and Adjustments). The Compensation Committee reviewed the impact of the 2014 Kemper IGCC Charges and Adjustments on goal achievement and payout levels for all Southern Company system employees, including the named executive officers. The Compensation Committee determined that, given the action taken last year and the high levels of achievement of other performance goals in 2014, it was not appropriate to reduce payouts earned in 2014 under the broad-based program applicable to all participating employees. Therefore, the Compensation Committee made an adjustment to exclude the impact of the 2014 Kemper IGCC Charges and Adjustments ($0.61 per share) from earnings as it relates to the EPS goal payout for most Southern Company system employees.

As described in greater detail below in Calculating Payouts, Mr. Burroughs is paid in part based on the equity-weighted average of the business unit net income results, which includes the net income goal achievement for Mississippi Power. Due to the 2014 Kemper IGCC Charges and Adjustments described above, Mississippi Power recorded a net loss of $328.7 million, resulting in below-threshold performance and would have resulted in no payout associated with the Mississippi Power portion of the net income goal for thousands of employees across the Southern Company system, including Mr. Burroughs, as well as no payout at all for the business unit financial goal for all Mississippi Power employees. With the adjustment made by the Compensation Committee, Mississippi Power's net income for purposes of calculating goal achievement was $224 million. The adjusted net income resulted in a higher payout for the net income goal for all Mississippi Power employees as well as a higher payout associated with the overall equity-weighted average net income results for several thousand other employees across the Southern Company system whose payouts are determined by the equity-weighted average of the business unit net income results, including Mr. Burroughs.

Under the terms of the program, no payout can be made if events occur that impact Southern Company's financial ability to fund the Common Stock dividend. The 2014 Kemper IGCC Charges and Adjustments described above did not have that effect.

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 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.
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.
Nuclear Plant Operations	Nuclear plant performance is evaluated by measuring nuclear safety as rated by independent industry evaluators, as well as by a quantitative score comprised of various plant performance indicators. Plant reliability and operational availability are measured as a percentage of time the nuclear plant is operating. The reliability and availability metrics take generation reductions associated with planned outages into consideration.	Safe and efficient operation of the nuclear fleet is important for delivering clean energy at a reasonable price.
Major Projects - Plant Vogtle Units 3 and 4 and Kemper IGCC	The Southern Company system is committed to the safe, compliant, and high-quality construction and licensing of two new nuclear generating units under construction at Georgia Power's Plant Vogtle (Plant Vogtle Units 3 and 4) and the Kemper IGCC, as well as excellence in transition to operations and prudent decision-making related to these two major projects. An executive review committee is in place for each project to assess progress. A combination of subjective and objective measures is considered in assessing the degree of achievement. Final assessments for each project are approved by either Southern Company's Chief Executive Officer or Southern Company's Chief Operating Officer and confirmed by the Nuclear/Operations Committee of Southern Company.	Strategic projects enable the Southern Company system to expand capacity to provide clean, affordable energy to customers across the region.
Safety	Southern Company's Target Zero program is focused on continuous improvement in having 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.

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.
Net Income	For the traditional operating companies, including Gulf Power, and Southern Power, the business unit financial performance goal is net income after dividends on preferred and preference stock.	Supports delivery of Southern Company stockholder value and contributes to Gulf Power's and Southern Company's sound financial policies and stable credit ratings.

The range of business unit and Southern Power net income goals and Southern Company EPS goals for 2014 is shown below. Overall Southern Company performance is determined by the equity-weighted average of the business unit net income goal payouts.

Level of Performance	Alabama Power ($, in millions)	Georgia Power ($, in millions)	Gulf Power ($, in millions)	Mississippi Power ($, in millions)*	Southern Power ($, in millions)	EPS ($)*
Maximum	774	1,258	153.0	240.7	175	2.90
Target	717	1,160	140.2	218.6	135	2.76
Threshold	661	1,063	127.4	196.4	95	2.62

*Excluding impact of the 2014 Kemper IGCC Charges and Adjustments.

The ranges of performance levels established for the primary operational goals are detailed below.

Level of Performance	Customer Satisfaction	Reliability	Availability	Nuclear Plant Operations	Safety	Plant Vogtle Units 3 and 4 and Kemper IGCC	Culture
Maximum	Top quartile for all customer segments and overall	Significantly exceed targets	Industry best	Significantly exceed targets	Greater than 90th percentile or 5-year company best	Significantly exceed targets	Significant improvement
Target	Top quartile overall	Meet targets	Top quartile	Meet targets	60th percentile	Meet targets	Improvement
Threshold	2nd quartile overall	Significantly below targets	2nd quartile	Significantly below targets	40th percentile	Significantly below targets	Significantly below expectations

The Compensation Committee approves specific objective performance schedules to calculate performance between the threshold, target, and maximum levels for each of the operational goals. If goal achievement is below threshold, there is no payout associated with the applicable goal.

2014 Achievement

Actual 2014 goal achievement is shown in the following tables.

Operational Goal Results:

Gulf Power (Ms. Terry and Messrs. Connally, Teel, Burroughs, Fletcher, and Jacob)

Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	184
Availability	200
Safety	30
Culture	127
Total Gulf Power Operational Goal Performance Factor	149

Southern Company Generation (Mr. Burroughs)

Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	195
Availability	190
Safety	150
Culture	141
Major Projects - Plant Vogtle Units 3 and 4 Assessment	175
Major Projects - Kemper IGCC Assessment	75
Total Southern Company Generation Operational Goal Performance Factor	168

Georgia Power (Mr. Fletcher)

Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	172
Availability	200
Safety	80
Culture	137
Major Projects - Plant Vogtle Units 3 and 4 Assessment	175
Total Georgia Power Operational Goal Performance Factor	162

Financial Performance Goal Results:

Goal	Result	Achievement Percentage (%)
Gulf Power Net Income	$140.18	100
Georgia Power Net Income	$1,225.01	166
Southern Power Net Income	$172.30	193
Corporate Net Income Result	Equity-Weighted Average[(1)]	163
EPS (from ongoing business activities)	$2.80[(2)]	176

(1) The Corporate Net Income Result is the equity-weighted average of the business unit net income results, including the net income result for Mississippi Power. Mississippi Power's net income result for this purpose was impacted by the adjustment for the 2014 Kemper IGCC Charges and Adjustments ($553 million on an after tax basis). Mississippi Power recorded a net loss, as determined in accordance with generally accepted accounting principles in the United States (GAAP), of $328.7 million. Payouts under the Performance Pay Program were determined using a net income performance result that differed from Mississippi Power's net income as determined in accordance with GAAP.

(2) The EPS result shown in the table excludes the 2014 Kemper IGCC Charges and Adjustments ($0.61 per share) as described above. EPS, as determined in accordance with GAAP, was $2.19 per share. Payouts under the Performance Pay Program were determined using an EPS performance result that different from EPS as determined in accordance with GAAP.

Calculating Payouts:

All of the named executive officers are paid based on Southern Company EPS performance. With the exception of Messrs. Burroughs and Fletcher, all of the named executive officers are paid based on Gulf Power net income and operational performance. Southern Company Generation officers, including Mr. Burroughs, are paid based on the goal achievement of the traditional operating company supported (60%) and Southern Company Generation (40%). The Southern Company Generation business unit financial goal is based on the equity-weighted average net income payout results of the traditional operating companies and Southern Power. With the exception of the culture and safety goals, Southern Company Generation's operational goal results are the corporate/aggregate operational goal results. Mr. Fletcher's payout is prorated based on the time he was employed at Georgia Power and at Gulf Power. Mr. Jacob's payout is prorated based on the amount of time he was employed at Gulf Power during 2014.

A total performance factor is determined by adding the applicable business unit financial and operational goal performance and the EPS results and dividing by three. The total performance factor is multiplied by the target Performance Pay Program opportunity to determine the payout for each named executive officer. The table below shows the calculation of the total performance factor for each of the named executive officers, based on results shown above.

	Southern Company EPS Result (%) 1/3 weight[1]	Business Unit Financial Goal Result (%) 1/3 weight	Business Unit Operational Goal Result (%) 1/3 weight	Total Performance Factor (%)
S. W. Connally, Jr.	176	100	149	142
R. S. Teel	176	100	149	142
M. L. Burroughs	176	125	156	152
J. R. Fletcher[2]	176	166/100	162/149	168/142
P. B. Jacob	176	100	149	142
B. C. Terry	176	100	149	142

(1) Excluding the impact of the 2014 Kemper IGCC Charges and Adjustments.

(2) Mr. Fletcher was Vice President of Georgia Power until his promotion to Vice President at Gulf Power on March 29, 2014. Under the terms of the program, Mr. Fletcher's Performance Pay Program results were prorated based on the time he served at each company.

The table below shows the pay opportunity at target-level performance and the actual payout based on the actual performance shown above.

	Target Annual Performance Pay Program Opportunity (%)	Target Annual Performance Pay Program Opportunity ($)	Total Performance Factor (%)	Actual Annual Performance Pay Program Payout ($)
S. W. Connally, Jr.	60	238,945	142	339,302
R. S. Teel	45	114,077	142	161,989
M. L. Burroughs	40	80,133	152	121,801
J. R. Fletcher[1]	40/45	101,343	147.7	149,633
P. B. Jacob[2]	45	120,198	142	57,008
B. C. Terry	45	122,418	142	173,833

(1) When Mr. Fletcher was promoted in March 2014, his target annual Performance Pay Program percentage was increased from 40% to 45%. His actual payout shown is prorated based on the amount of time he spent in each position.

(2) Mr. Jacob retired from Gulf Power in May 2014. His Performance Pay Program payout was prorated based on the amount of time he was employed in 2014. The target amount shown is his full target had he been employed for the entire year. The actual amount shown is the prorated amount Mr. Jacob received.

Long-Term Performance-Based Compensation

2014 Long-Term Pay Program Highlights

- Stock Options:
  - Reward long-term Common Stock price appreciation
  - Represent 40% of long-term target value
  - Vest over three years
  - Ten-year term
- Performance Shares:
  - Reward Southern Company total shareholder return relative to industry peers and stock price appreciation
  - Represent 60% of long-term target value
  - Three-year performance period
  - Performance results can range from 0% to 200% of target
  - Paid in Common Stock at end of performance period

Long-term performance-based awards are intended to promote long-term success and increase Southern Company's stockholder value by directly tying a substantial portion of the named executive officers' total compensation to the interests of Southern Company's stockholders. Long-term performance-based awards also benefit customers by providing competitive compensation that allows Gulf Power to attract, retain, and engage employees who provide focus on serving customers and delivering safe and reliable electric service.

Southern Company stock options represent 40% of the long-term performance target value and performance shares represent the remaining 60%. The Compensation Committee elected this mix because it concluded that doing so represented an appropriate balance between incentives. Southern Company stock options only generate value if the price of the stock appreciates after the grant date, and performance shares reward employees based on Southern Company total shareholder return relative to industry peers, as well as Common Stock price.

The following table shows the grant date fair value of the long-term performance-based awards granted in 2014.

	Value of Options ($)	Value of Performance Shares ($)	Total Long-Term Value ($)
S. W. Connally, Jr.	207,086	310,606	517,692
R. S. Teel	60,841	91,260	152,101
M. L. Burroughs	32,052	48,051	80,103
J. R. Fletcher	33,801	50,679	84,480
P. B. Jacob	64,106	96,140	160,246
B. C. Terry	65,287	97,904	163,191

Stock Options

Stock options granted have a 10-year term, vest over a three-year period, fully vest upon retirement or termination of employment following a change in control, and expire at the earlier of five years from the date of retirement or the end of the 10-year term. For the grants made in 2014 to Mr. Connally, unvested options are forfeited if he retires from Gulf Power or an affiliate of Gulf Power and accepts a position with a peer company within two years of retirement. The grants made to Mr. Jacob vested upon his retirement. The value of each stock option was derived using the Black-Scholes stock option pricing model. The assumptions used in calculating that amount are discussed in Note 8 to the financial statements of Gulf Power in Item 8 herein. For 2014, the Black-Scholes value on the grant date was $2.20 per stock option.

Performance Shares

2014-2016 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 grants made in 2014, the value per unit was $37.54. See the Summary Compensation Table and the information accompanying it for more information on the grant date fair value. 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.

At the end of the three-year performance period (January 1, 2014 through December 31, 2016), the number of units will be adjusted up or down (0% to 200%) based on Southern Company's total shareholder return relative to that of its peers in the Southern Company custom peer group. While in previous years Southern Company's total shareholder return was measured relative to two peer groups (a custom peer group and the Philadelphia Utility Index), the Compensation Committee decided to streamline the performance share peer group for the 2014 grant by eliminating the Philadelphia Utility Index and establishing one custom peer group. The companies in the custom peer group are those that are believed to be most similar to Southern Company in both business model and investors, creating a peer group that is even more aligned with Southern Company's strategy. For performance shares granted in previous years using the dual peer group structure, the final result will be measured using both peer groups as approved by the Compensation Committee at the time of the grant. The custom peer group varies from the Market Data peer group discussed previously due to the timing and criteria of the peer selection process; however, there is significant overlap. The number of performance share units earned will be paid in Common Stock at the end of the three-year performance period. No dividends or dividend equivalents will be paid or earned on the performance share units. The peers in the custom peer group on the grant date are listed in the following table.

Alliant Energy Corporation	Integrys Energy Group
Ameren Corporation	Pepco Holdings, Inc.
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	Wisconsin Energy Corporation
Edison International	Xcel Energy
Eversource International	

The scale below will determine the number of units paid in Common Stock following the last year of the performance period, based on the 2014 through 2016 performance period. Payout for performance between points will be interpolated on a straight-line basis.

Performance vs. Peer Group	Payout (% of Each Performance Share Unit Paid)
90th percentile or higher (Maximum)	200
50th percentile (Target)	100
10th percentile (Threshold)	0

Performance shares are not earned until the end of the three-year performance period. A participant who terminates, other than due to retirement or death, forfeits all unearned performance shares. Participants who retire or die during the performance period only earn a prorated number of units, based on the number of months they were employed during the performance period.

2012-2014 Payouts

Performance share grants were made in 2012 with a three-year performance period that ended on December 31, 2014. Based on Southern Company's total shareholder return achievement relative to that of the Philadelphia Utility Index (28% payout) and the custom peer group (0% payout), the payout percentage was 14% of target, which is the average of the two peer groups. The following table shows the target and actual awards of performance shares for the named executive officers.

	Target Performance Shares (#)	Target Value of Performance Shares ($)	Performance Shares Earned (#)	Value of Performance Shares Earned ($)
S. W. Connally, Jr.	1,944	81,629	272	13,358
R. S. Teel	2,049	86,038	287	14,095
M. L. Burroughs	1,081	45,391	151	7,416
J. R. Fletcher	1,136	47,700	159	7,808
P. B. Jacob[(1)]	2,185	91,748	238	11,688
B. C. Terry	2,199	92,336	308	15,126

(1) The number of performance shares earned by Mr. Jacob is prorated based on the time he was employed at the Southern Company system during the performance period.

Timing of Performance-Based Compensation

As discussed above, the 2014 annual Performance Pay Program goals and the Southern Company total shareholder return goals applicable to performance shares were established early in the year by the Compensation Committee. Annual stock option grants also were made by the Compensation Committee. The establishment of performance-based compensation goals and the granting of equity awards were not timed with the release of material, non-public information. This procedure is consistent with prior practices. Stock option grants are made to new hires or newly-eligible participants on preset, regular quarterly dates that were approved by the Compensation Committee. The exercise price of options granted to employees in 2014 was the closing price of the Common Stock on the grant date or the last trading day before the grant date, if the grant date was not a trading day.

Southern Excellence Awards

Mr. Fletcher received a discretionary award in the amount of $25,000 in recognition of his leadership and superior performance on high-level regulatory matters while employed at Georgia Power in 2014, prior to his employment at Gulf Power.

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

Generally, all full-time employees of Gulf Power participate in the funded Pension Plan after completing one year of service. Normal retirement benefits become payable when participants attain age 65 and complete five years of participation. Gulf Power also provides unfunded benefits that count salary and annual Performance Pay Program payouts that are ineligible to be counted under the Pension Plan. See the Pension Benefits table and accompanying information for more pension-related benefits information.

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. 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, 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 Deferred Compensation Plan. See the Nonqualified Deferred Compensation table and accompanying information for more information about the Deferred Compensation Plan.

Severance Agreements

In limited circumstances, Gulf Power will provide a severance agreement in exchange for standard legal releases, non-compete agreements, and confidentiality provisions. In connection with Mr. Jacob's retirement in 2014, Gulf Power entered into a severance agreement with Mr. Jacob providing for a severance payment of $667,768, which is included in the Summary Compensation Table.

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. Severance payment amounts are 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. More information about severance arrangements is included under Potential Payments upon Termination or Change in Control. 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 ongoing 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 2014, including amounts, are described in detail in the information accompanying the Summary Compensation Table. No tax assistance is provided on perquisites for the President and Chief Executive Officer, except on certain relocation-related benefits.

PERFORMANCE-BASED COMPENSATION PROGRAM CHANGES FOR 2015

In early 2015, the Compensation Committee made several changes to the performance-based compensation programs, impacting 2015 compensation. These changes affect both the annual Performance Pay Program as well as the long-term performance-based compensation program and are described below.

Annual Performance-Based Pay Program

Beginning in 2015, the annual performance-based pay program will incorporate individual goals for all executive officers of Southern Company, including Mr. Connally. Currently, the goals are equally weighted between the EPS goal, the applicable business unit net income goal, and the applicable business unit operational goals. Starting with the 2015 annual Performance Pay Program goals, the Compensation Committee added an individual goal component (weighted 10%), and changed the weights for the EPS goal and business unit financial and operational goals (weighted 30% each) for Mr. Connally. The other named executive officers were not affected by this change.

Long-Term Performance-Based Compensation

Since 2010, the Southern Company system's long-term performance-based compensation program has included two components: stock options and performance shares. After reviewing current market practices with Pay Governance, the Compensation Committee decided to modify the long-term performance-based compensation program to further align the compensation program with peers in the utility industry and create better alignment of pay with long-term performance. Beginning with long-term performance-based equity grants made in early 2015, the long-term performance-based program consists exclusively of performance shares. The new structure maintains the three-year performance cycle described earlier in this CD&A for performance shares but expands the performance metrics from one (relative total shareholder return) to three metrics. The new program now includes relative total shareholder return (50%), cumulative EPS from ongoing operations over a three-year period (25%), and equity-weighted return on equity (ROE) (25%). Under the new program, dividends will accrue on performance shares throughout the performance period, and eligible new hires and newly promoted employees will receive interim prorated grants of performance shares instead of stock options.

The continued use of relative total shareholder return as a metric in the long-term performance program maintains consistency with the previous program as well as allows Southern Company to measure its performance against a custom group of regulated peers. The new EPS goal measures cumulative EPS from ongoing operations over a three-year period and motivates ongoing earnings growth to support Southern Company's dividends and achievement of strategic financial objectives. The new equity-weighted ROE goal measures traditional operating company performance from ongoing operations over a three-year period and is set to encourage

top quartile ROE performance. Both the EPS and ROE goals are subject to a gateway goal focused on Southern Company's credit ratings. If Southern Company fails to meet the credit rating requirements established by the Compensation Committee, there will be no payout associated with the EPS and ROE goals.

EXECUTIVE STOCK OWNERSHIP REQUIREMENTS

Officers of Gulf Power that are in a position of Vice President or above are subject to stock ownership requirements. All of the name executive officers are covered by the requirements. Ownership requirements further align the interest of officers and Southern Company's stockholders by promoting a long-term focus and long-term share ownership. The types of ownership arrangements counted toward the requirements are shares owned outright, those held in Southern Company-sponsored plans, and Common Stock accounts in the Deferred Compensation Plan and the Supplemental Benefit Plan. One-third of vested Southern Company stock options may be counted, but, if so, the ownership requirement is doubled. 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 1/3 of Vested Options
S. W. Connally, Jr.	3 Times	6 Times
R. S. Teel	2 Times	4 Times
M. L. Burroughs	1 Times	2 Times
J. R. Fletcher	2 Times	4 Times
B. C. Terry	2 Times	4 Times

Newly-elected officers have approximately five years from the date of their election to meet the applicable ownership requirement. Newly-promoted officers have approximately five years from the date of their promotion to meet the increased ownership requirements. All of the named executive officers are meeting their respective ownership requirement. Mr. Jacob is retired and is therefore no longer subject to stock ownership requirements.

POLICY ON RECOVERY 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 Powe 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 THE ECONOMIC RISK OF STOCK OWNERSHIP

Southern Company's policy is that employees and outside directors will not trade Southern Company options on the options market and will not engage in short sales.

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, 2014. The Southern Company Board of Directors approved that recommendation.

Members of the Compensation Committee:

Henry A. Clark III, Chair
David J. Grain
Veronica M. Hagen
William G. Smith, Jr.
Steven R. Specker

SUMMARY COMPENSATION TABLE

The Summary Compensation Table shows the amount and type of compensation received or earned in 2012, 2013, and 2014 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.	2014	393,907	—	310,606	207,086	339,302	496,800	25,948	1,773,649
President, Chief	2013	372,977	—	293,018	195,363	164,557	54,607	25,602	1,106,124
Executive Officer, and Director	2012	295,103	24,376	81,629	54,420	249,526	431,809	179,308	1,316,171
R. S. Teel	2014	252,110	—	91,260	60,841	161,989	157,002	17,166	740,368
Vice President and Chief Financial	2013	244,903	—	88,614	59,101	80,895	—	17,004	490,517
Officer	2012	236,882	—	86,038	57,379	143,335	118,474	15,610	657,718
M. L. Burroughs	2014	199,209	—	48,051	32,052	121,801	213,219	9,893	624,225
Vice President	2013	193,498	—	46,656	31,118	59,127	—	11,225	341,624
	2012	187,855	—	45,391	30,269	94,634	204,035	12,218	574,402
J. R. Fletcher	2014	224,547	25,045	50,679	33,801	149,633	273,148	89,971	846,824
Vice President									
P. B. Jacob	2014	94,293	—	96,140	64,106	57,008	316,172	681,567	1,309,286
Former Vice	2013	258,605	—	93,393	62,272	85,236	—	19,033	518,539
President	2012	253,959	—	91,748	61,169	145,616	310,532	16,671	879,695
B. C. Terry	2014	270,543	—	97,904	65,287	173,833	245,578	17,664	870,809
Vice President	2013	262,809	—	95,094	63,419	86,809	—	16,735	524,866
	2012	255,634	—	92,336	61,573	159,332	210,941	16,910	796,726

Column (a)

Mr. Fletcher was not an executive officer of Gulf Power until 2014.

Column (d)

The amount shown for 2014 for Mr. Fletcher represents a Southern Excellence Award as described in the CD&A and the value of a non-cash safety award he received while employed at Georgia Power. All employees of Georgia Power with a perfect individual safety record in the prior year, including Mr. Fletcher, earned a safety award.

Column (e)

This column does not reflect the value of stock awards that were actually earned or received in 2014. Rather, as required by applicable rules of the SEC, this column reports the aggregate grant date fair value of performance shares granted in 2014. The value reported is based on the probable outcome of the performance conditions as of the grant date, using a Monte Carlo simulation model. No amounts will be earned until the end of the three-year performance period on December 31, 2016. 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 2014 to Ms. Terry and Messrs. Connally, Teel, Burroughs, and Fletcher, assuming that the highest level of performance is achieved, is $195,808, $621,212, $182,520, $96,102, and $101,358, respectively (200% of the amount shown in the table). Because Mr. Jacob retired from Gulf Power on May 3, 2014, the maximum amount he could earn is $21,398, which is prorated based on the number of months he was employed during the performance period. 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)

This column reports the aggregate grant date fair value of stock options granted in the applicable year. 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 (g)

The amounts in this column are the payouts under the annual Performance Pay Program. The amount reported for the Performance Pay Program is for the one-year performance period that ended on December 31, 2014. 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, 2012, 2013, and 2014. Because Mr. Jacob retired in 2014, the amount reported for him in 2014 reflects the actual benefits expected to be paid after the measurement date. 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 any 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. In general, all of the named executive officers saw an increase in their pension values due to a decrease in discount rates and updated mortality rates.

For more information about the Pension Benefits and the assumptions used to calculate the actuarial present value of accumulated benefits as of December 31, 2014, see the information following the Pension Benefits table. The key differences between assumptions used for the actuarial present values of accumulated benefits calculations as of December 31, 2013 and December 31, 2014 are:

- Discount rate for the Pension Plan was decreased to 4.20% as of December 31, 2014 from 5.05% as of December 31, 2013,
- Discount rate for the supplemental pension plans was decreased to 3.75% as of December 31, 2014 from 4.50% as of December 31, 2013, and
- Mortality rates for all plans were updated due to the release of new mortality tables.

This column also reports above-market earnings on deferred compensation under the Deferred Compensation Plan (DCP). However, there were no above-market earnings on deferred compensation in the years reported.

Column (i)

This column reports the following items: perquisites; severance payments; tax reimbursements; employer contributions in 2014 to the Southern Company Employee Savings Plan (ESP), which is a tax-qualified defined contribution plan intended to meet requirements of Section 401(k) of the Internal Revenue Code of 1986, as amended (Code); and contributions in 2014 under the Southern Company Supplemental Benefit Plan (Non-Pension Related) (SBP). The SBP is described more fully in the information following the Nonqualified Deferred Compensation table.

The amounts reported for 2014 are itemized below.

	Perquisites ($)	Severance Payments ($)	Tax Reimbursements ($)	ESP ($)	SBP ($)	Total ($)
S. W. Connally, Jr.	5,858	—	—	11,709	8,381	25,948
R. S. Teel	4,937	—	314	11,915	—	17,166
M. L. Burroughs	1,203	—	102	8,588	—	9,893
J. R. Fletcher	48,432	—	30,087	11,452	—	89,971
P. B. Jacob	6,997	667,768	1,899	4,903	—	681,567
B. C. Terry	5,446	—	515	11,165	538	17,664

Description of Perquisites

Personal Financial Planning is provided for most officers of Gulf Power, including all of the named executive officers. Gulf Power pays for the services of a financial planner on behalf of the officers, up to a maximum amount of $8,700 per year, after the initial year that the benefit is provided. In the initial year, the allowed amount is $15,000. Gulf Power also provides a five-year allowance of $6,000 for estate planning and tax return preparation fees.

Relocation Benefits are provided to cover the costs associated with geographic relocation. In 2014, Mr. Fletcher received relocation-related benefits in the amount of $37,322 in connection with his 2014 relocation from Atlanta, Georgia to Pensacola, Florida. This amount was for the shipment of household goods, incidental expenses related to his move, and 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 Mr. Fletcher terminates within two years of his relocation, these amounts must be repaid.

Personal Use of Corporate Aircraft. 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. 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. In connection with Mr. Fletcher's relocation from Atlanta, Georgia to Pensacola, Florida, Mr. Connally approved personal use of the corporate aircraft for one round-trip flight per month for six months. The perquisite amount shown for Mr. Fletcher includes $8,847 for this approved use of corporate aircraft.

Other Miscellaneous Perquisites. The amount included reflects the full cost to Gulf Power of providing the following items: 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 2014

This table provides information on stock option grants made and goals established for future payouts under the performance-based compensation programs during 2014 by the Compensation Committee.

Name (a)	Grant Date (b)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Option Awards: Number of Securities Underlying Options (#) (i)	Exercise or Base Price of Option Awards ($/Sh) (j)	Grant Date Fair Value of Stock and Option Awards ($) (k)
		Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)			
S. W. Connally, Jr.		2,389	238,945	477,890						
	2/10/2014				82	8,274	16,548			310,606
	2/10/2014							94,130	41.28	207,086
R. S. Teel		1,141	114,077	228,154						
	2/10/2014				24	2,431	4,862			91,260
	2/10/2014							27,655	41.28	60,841
M. L. Burroughs		801	80,133	160,265						
	2/10/2014				12	1,280	2,560			48,051
	2/10/2014							14,569	41.28	32,052
J. R. Fletcher		1,013	101,343	202,686						
	2/10/2014				13	1,350	2,700			50,679
	2/10/2014							15,364	41.28	33,801
P. B. Jacob		401	40,146	80,292						
	2/10/2014				25	2,561	5,122			96,140
	2/10/2014							29,139	41.28	64,106
B. C. Terry		1,224	122,418	244,836						
	2/10/2014				26	2,608	5,216			97,904
	2/10/2014							29,676	41.28	65,287

Columns (c), (d), and (e)

These columns reflect the annual Performance Pay Program opportunity granted to the named executive officers in 2014 as described in the CD&A. The information shown as "Threshold," "Target," and "Maximum" reflects the range of potential payouts established by the Compensation Committee. The actual amounts earned are disclosed in the Summary Compensation Table. The amounts shown for Mr. Jacob are prorated based on the amount of time he was employed at Gulf Power in 2014. The amounts shown for Mr. Fletcher reflect the increase in salary and annual Performance Pay Program opportunity he received after his promotion to Vice President of Gulf Power on March 29, 2014.

Columns (f), (g), and (h)

These columns reflect the performance shares granted to the named executive officers in 2014 as described in the CD&A. The information shown as "Threshold," "Target," and "Maximum" reflects the range of potential payouts established by the Compensation Committee. Earned performance shares will be paid out in Common Stock following the end of the 2014 through 2016 performance period, based on the extent to which the performance goals are achieved. Any shares not earned are forfeited.

The number of shares shown for Mr. Jacob reflects the full grant he received in February 2014. However, since Mr. Jacob retired in May 2014, the ultimate number of performance shares he will receive will be prorated based on the number of months he was employed by the Southern Company system during the performance period.

Columns (i) and (j)

Column (i) reflects the number of stock options granted to the named executive officers in 2014, as described in the CD&A, and column (j) reflects the exercise price of the stock options, which was the closing price on the grant date.

Column (k)

This column reflects the aggregate grant date fair value of the performance shares and stock options granted in 2014. For performance shares, the value is based on the probable outcome of the performance conditions as of the grant date using a Monte Carlo simulation model. For stock options, the value is derived using the Black-Scholes stock option pricing model.

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 2014 FISCAL YEAR-END

This table provides information pertaining to all outstanding stock options and stock awards (performance shares) held by or granted to the named executive officers as of December 31, 2014.

	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.						
	8,521	0	35.78	02/18/2018		
	14,392	0	31.39	02/16/2019		
	16,100	0	37.97	02/14/2021		
	10,702	5,351	44.42	02/13/2022		
	22,302	44,603	44.06	02/11/2023		
	0	94,130	41.28	02/10/2024		
					7,235	355,311
					8,274	406,336
R. S. Teel	9,078	0	35.78	02/18/2018		
	9,332	0	31.39	02/16/2019		
	9,629	0	31.17	02/15/2020		
	16,774	0	37.97	02/14/2021		
	11,284	5,642	44.42	02/13/2022		
	6,747	13,493	44.06	02/11/2023		
	0	27,655	41.28	02/10/2024		
					2,188	107,453
					2,431	119,386
M. L. Burroughs	289	0	33.81	02/20/2016		
	1,604	0	36.42	02/19/2017		
	2,610	0	35.78	02/18/2018		
	1,207	0	31.17	02/15/2020		
	8,956	0	37.97	02/14/2021		
	5,953	2,976	44.42	02/13/2022		
	3,553	7,104	44.06	02/11/2023		
	0	14,569	41.28	02/10/2024		
					1,152	56,575
					1,280	62,861
J. R.Fletcher	3,376	0	37.97	02/14/2021		
	6,247	3,124	44.42	02/13/2022		
	3,728	7,456	44.06	02/11/2023		
	0	15,364	41.28	02/10/2024		
					1,209	59,374
					1,350	66,299
P. B. Jacob	0	0				
					2,306	113,248
					2,561	125,771
B. C. Terry	12,918	0	35.78	02/18/2018		
	18,574	0	37.97	02/14/2021		
	12,109	6,054	44.42	02/13/2022		
	7,240	14,479	44.06	02/11/2023		
	0	29,676	41.28	02/10/2024		
					2,348	115,310
					2,608	128,079

Columns (b), (c), (d), and (e)

Stock options vest one-third per year on the anniversary of the grant date. Options granted from 2006 through 2011 with expiration dates from 2016 through 2021 were fully vested as of December 31, 2014. The options granted in 2012, 2013, and 2014 become fully vested as shown below.

Year Option Granted	Expiration Date	Date Fully Vested
2012	February 13, 2022	February 13, 2015
2013	February 11, 2023	February 11, 2016
2014	February 10, 2024	February 10, 2017

Options also fully vest upon death, total disability, or retirement and expire three years following death or total disability or five years following retirement, or on the original expiration date if earlier. Please see Potential Payments upon Termination or Change in Control for more information about the treatment of stock options under different termination and change-in-control events.

Columns (f) and (g)

In accordance with SEC rules, column (f) reflects the target number of performance shares that can be earned at the end of each three-year performance period (December 31, 2015 and 2016) that were granted in 2013 and 2014, respectively. The performance shares granted for the 2012 through 2014 performance period vested December 31, 2014 and are shown in the Option Exercises and Stock Vested in 2014 table below. The value in column (g) is derived by multiplying the number of shares in column (f) by the Common Stock closing price on December 31, 2014 ($49.11). The ultimate number of shares earned, if any, will be based on the actual performance results at the end of each respective performance period. The ultimate number of shares earned by Mr. Jacob will be prorated based on the number of months he was employed by the Southern Company system during the performance periods. See further discussion of performance shares in the CD&A. See also Potential Payments upon Termination or Change in Control for more information about the treatment of performance shares under different termination and change-in-control events.

OPTION EXERCISES AND STOCK VESTED IN 2014

	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.	21,795	274,917	272	13,358
R. S. Teel	15,265	168,574	287	14,095
M. L. Burroughs	—	—	151	7,416
J. R. Fletcher	6,905	58,915	159	7,808
P. B. Jacob	112,474	758,786	238	11,688
B. C. Terry	39,302	494,815	308	15,126

Columns (b) and (c)

Column (b) reflects the number of shares acquired upon the exercise of stock options during 2014 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)

Column (d) includes the performance shares awarded for the 2012 through 2014 performance period that vested on December 31, 2014. The value reflected in column (e) is derived by multiplying the number of shares in column (d) by the market value of the underlying shares on the vesting date ($49.11).

PENSION BENEFITS AT 2014 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	23.17	595,352	0
	SBP-P	23.17	454,047	0
S.W. Connally, Jr.	SERP	23.17	351,143	0
	Pension Plan	14.33	349,590	0
	SBP-P	14.33	42,360	0
R. S. Teel	SERP	14.33	95,548	0
	Pension Plan	22.58	637,373	0
	SBP-P	22.58	64,888	0
M. L. Burroughs	SERP	22.58	133,832	0
	Pension Plan	24.58	585,977	0
	SBP-P	24.58	101,222	0
J. R. Fletcher	SERP	24.58	176,582	0
	Pension Plan	30.75	1,419,925	46,851
	SBP-P	30.75	269,172	28,796
P. B. Jacob	SERP	30.75	263,763	28,218
	Pension Plan	12.50	334,389	0
	SBP-P	12.50	52,591	0
	SERP	12.50	90,190	0
B. C. Terry	SRA	10.00	397,417	0

Pension Plan

The Pension Plan is a tax-qualified, funded plan. It is Southern Company's primary retirement plan. Generally, all full-time 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 pay out 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 2014 was $260,000.

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 of pay.

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, 2014, Ms. Terry and Messrs. Connally, Fletcher, and Teel were not 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 spouse. 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, 2014, 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.

If a participant dies while actively employed and is either age 50 or vested in the Pension Plan as of date of death, benefits will be paid to a surviving spouse. A survivor's benefit equals 45% of the monthly benefit that the participant had earned before his or her death. Payments to a surviving spouse of a participant who could have retired will begin immediately. Payments to a survivor of a participant who was not retirement-eligible will begin when the deceased participant would have attained age 50.

After commencing, survivor benefits are payable monthly for the remainder of a survivor's life. Participants who are eligible for early retirement may opt to have an 80% survivor benefit paid if they die; however, there is a charge associated with this election.

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 Southern Company Supplemental Benefit Plan (Pension-Related) (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 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 spouse of the deceased participant will receive the installments the participant would have been paid upon retirement. If a vested participant's death occurs prior to age 50, the installments will be paid to a spouse as if the participant had survived to age 50.

The Southern Company Supplemental Executive Retirement Plan (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.

Supplemental Retirement Agreements (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 - 4.20% Pension Plan and 3.75% supplemental plans as of December 31, 2014,
- Retirement date - Normal retirement age (65 for all named executive officers),
- Mortality after normal retirement - RP-2014 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: 75% single life annuity; 15% level income annuity; 5% 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.

Columns (d) and (e)

For Mr. Jacob, who retired May 3, 2014, column (d) reflects the actual benefits expected to be paid, and column (e) reflects the actual amount paid under the Pension Plan, the SBP-P, and the SERP in 2014, as described above.

NONQUALIFIED DEFERRED COMPENSATION AS OF 2014 FISCAL YEAR-END

Name (a)	Executive Contributions in Last FY ($) (b)	Registrant Contributions in Last FY ($) (c)	Aggregate Earnings in Last FY ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE ($) (f)
S. W. Connally, Jr.	—	8,381	6,690	—	127,836
R. S. Teel	—	—	33	—	162
M. L. Burroughs	—	—	—	—	—
J. R. Fletcher	—	—	—	—	—
P. B. Jacob	8,524	—	45,110	49,994	413,995
B. C. Terry	43,405	538	25,998	—	270,397

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.

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 2014, the rate of return in the Stock Equivalent Account was 25.27%.

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 2014 in the Prime Equivalent Account was 3.25%.

Column (b)

This column reports the actual amounts of compensation deferred under the DCP by each named executive officer in 2014. 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 2014 were the amounts that were earned as of December 31, 2013 but not payable until the first quarter of 2014. These amounts are not reflected in the Summary Compensation Table because that table reports performance-based compensation that was earned in 2014, but not payable until early 2015. 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 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 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 both 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' Information Statements or Annual Reports on Form 10-K. The following chart shows the amounts reported in Gulf Power's prior years' Information Statements or Annual Reports on Form 10-K.

Name	Amounts Deferred under the DCP Prior to 2014 and Reported in Prior Years' Information Statements or Annual Reports on Form 10-K ($)	Employer Contributions under the SBP Prior to 2014 and Reported in Prior Years' Information Statements or Annual Reports on Form 10-K ($)	Total ($)
S. W. Connally, Jr.	31,742	10,506	42,248
R. S. Teel	—	—	—
M. L. Burroughs	—	—	—
J. R. Fletcher	—	—	—
P. B. Jacob	282,289	23,274	305,563
B. C. Terry	243,752	950	244,702

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, 2014 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, 2014 and assumes that the price of Common Stock is the closing market price on December 31, 2014.

Description of Termination and Change-in-Control Events

The following charts list different types of termination and change-in-control events that can affect the treatment of payments under the compensation and benefit programs. 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. (See the description of Good Reason below.)

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 Gulf Power'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 shareholders own less than 50% of Southern Company surviving the merger.
- Southern Company Termination - Consummation of a merger or other event and Southern Company is not the surviving company or the Common Stock is no longer publicly traded.
- Gulf Power Change in Control - Consummation of an acquisition by another entity, other than another subsidiary of Southern Company, of 50% or more of the stock of Gulf Power, consummation of a merger with another entity and Gulf Power is not the surviving company, or the sale of substantially all the assets of Gulf Power.

At the employee level:

- Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason - Employment is terminated within two years of a change in control, other than for cause, or the employee voluntarily terminates for Good Reason. Good Reason for voluntary termination within two years of a change in control generally is satisfied when there is a material reduction in salary, performance-based compensation opportunity or benefits, relocation of over 50 miles, or a diminution in duties and responsibilities.

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

Program	Retirement/ Retirement-Eligible	Lay Off (Involuntary Termination Not For Cause)	Resignation	Death or Disability	Involuntary Termination (For Cause)
Pension Benefits Plans	Benefits payable as described in the notes following the Pension Benefits table.	Same as Retirement.	Same as Retirement.	Same as Retirement.	Same as Retirement.
Annual Performance Pay Program	Prorated if retire before 12/31.	Same as Retirement.	Forfeit.	Same as Retirement.	Forfeit.
Stock Options	Vest; expire earlier of original expiration date or five years.	Vested options expire in 90 days; unvested are forfeited.	Same as Lay Off.	Vest; expire earlier of original expiration date or three years.	Forfeit.
Performance Shares	Prorated if retire prior to end of performance period.	Forfeit.	Forfeit.	Same as Retirement.	Forfeit.
Financial Planning Perquisite	Continues for one year.	Terminates.	Terminates.	Same as Retirement.	Terminates.
Deferred Compensation Plan	Payable per prior elections (lump sum or up to 10 annual installments).	Same as Retirement.	Same as Retirement.	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.	Same as Retirement.
SBP - non-pension related	Payable per prior elections (lump sum or up to 20 annual installments).	Same as Retirement.	Same as Retirement.	Same as the Deferred Compensation Plan.	Same as Retirement.

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 Termination 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 - pension- related 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.	Same as Southern Company Change-in-Control II.	Based on type of change-in-control event.
SRA	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.	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.	Same as Southern Company Change-in-Control I.	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 by change-in-control events.	Not affected by change-in-control events.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
Performance Shares	Not affected by change-in-control events.	Not affected by change-in-control events.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
DCP	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.

Program	Southern Company Change-in-Control I	Southern Company Change-in-Control II	Southern Company Termination or Gulf Power Change in Control	Involuntary Change-in-Control-Related Termination or Voluntary Change-in-Control-Related Termination for Good Reason
SBP	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.
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, 2014.

Pension Benefits

The amounts that would have become payable to the named executive officers if the Traditional Termination Events occurred as of December 31, 2014 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, 2014 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, 2014 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. Of the named executive officers, Ms. Terry and Messrs. Connally, Fletcher, and Teel were not retirement-eligible on December 31, 2014. The SRA for Ms. Terry contains an additional service requirement for benefit eligibility which was not met as of December 31, 2014. 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	2,182	3,583
	SBP-P	n/a	453,210	58,157
	SERP	n/a	—	44,977
R. S. Teel	Pension	n/a	1,301	2,163
	SBP-P	n/a	42,275	5,510
	SERP	n/a	—	12,428
M. L. Burroughs	Pension	3,657	All plans treated as retiring	2,697
	SBP-P	7,426		7,426
	SERP	15,316		15,316
J. R. Fletcher	Pension	n/a	1,883	3,093
	SBP-P	n/a	101,166	11,468
	SERP	n/a	—	20,006
B. C. Terry	Pension	n/a	1,181	1,940
	SBP-P	n/a	52,331	6,861
	SERP	n/a	—	11,767
	SRA	n/a	—	51,850

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, 2014 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.	443,482	342,972	—	786,454
R. S. Teel	41,367	93,310	—	134,677
M. L. Burroughs	74,260	153,162	—	227,422
J. R. Fletcher	98,994	172,695	—	271,689
B. C. Terry	51,207	87,817	386,959	525,983

The pension benefit amounts in the tables above were calculated as of December 31, 2014 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 3.79% discount rate.

Annual Performance Pay Program

The amount payable if a change in control had occurred on December 31, 2014 is the greater of target or actual performance. Because actual payouts for 2014 performance were above the target level, the amount that would have been payable was the actual amount paid as reported in the CD&A.

Stock Options and Performance Shares (Equity Awards)
Equity Awards would be treated as described in the Termination and Change-in-Control charts above. Under a Southern Company Termination, all Equity Awards vest. In addition, if there is an Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason, Equity Awards vest. There is no payment associated with Equity Awards unless there is a Southern Company Termination and 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. For stock options, the value is the excess of the exercise price and the closing price of Common Stock on December 31, 2014. The value of performance shares is calculated using the closing price of Common Stock on December 31, 2014.

The chart below shows the number of stock options for which vesting would be accelerated under a Southern Company Termination and the amount that would be payable under a Southern Company Termination 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.	144,084	15,509	216,101	15,509	2,459,809
R. S. Teel	46,790	4,619	109,634	4,619	1,270,952
M. L. Burroughs	24,649	2,432	48,821	2,432	510,197
J. R. Fletcher	25,944	2,559	39,295	2,559	384,010
B. C. Terry	50,209	4,956	101,050	4,956	1,049,729

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. Burroughs is retirement-eligible. Healthcare benefits are provided to retirees, and there is no incremental payment associated with the termination or change-in-control events. Because the other named executive officers were not retirement-eligible at the end of 2014, 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 healthcare insurance premiums for up to a maximum of two years for Ms. Terry and Messrs. Fletcher and Teel is $11,322, $29,563, and $29,563, respectively. The estimated cost of providing healthcare insurance premiums for up to a maximum of three years for Mr. Connally is $46,028.

Financial Planning Perquisite
An additional year of the Financial Planning perquisite, which is set at a maximum of $8,700 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.

The estimated cost of providing the six months of outplacement services is $6,000 per named executive officer. The severance payment is 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. If any portion of the severance amount constitutes an "excess parachute payment" under Section 280G of the 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, 2014 in connection with a change in control.

Name	Severance Amount ($)
S. W. Connally, Jr.	1,274,374
R. S. Teel	367,581
M. L. Burroughs	280,464
J. R. Fletcher	332,667
B. C. Terry	394,457

DIRECTOR COMPENSATION

Only non-employee directors of Gulf Power are compensated for service on the board of directors.

During 2014, 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 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;
- at prime interest 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.

DIRECTOR COMPENSATION TABLE

The following table reports all compensation to Gulf Power's non-employee directors during 2014, 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]	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)[3]	Total ($)
Allan G. Bense	24,400	19,500	0	138	44,038
Deborah H. Calder	24,400	19,500	0	79	43,979
William C. Cramer, Jr.	24,400	19,500	0	79	43,979
Julian B. MacQueen	24,400	19,500	0	138	44,038
J. Mort O'Sullivan III	24,400	19,500	0	303	44,203
Michael T. Rehwinkel	24,400	19,500	0	138	44,038
Winston E. Scott	23,200	19,500	0	107	42,807

(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) Consists of reimbursement for taxes on imputed income associated with gifts and activities provided to attendees at Southern Company system-sponsored events.

COMPENSATION RISK ASSESSMENT

Southern Company reviewed its compensation policies and practices, including those of Gulf Power, and concluded that excessive risk-taking is not encouraged. This conclusion was based on an assessment of the mix of pay components and performance goals, the

annual pay/performance analysis by the Compensation Committee's independent consultant, stock ownership requirements, compensation governance practices, and the claw-back provision. The assessment was reviewed with the Compensation Committee.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The Compensation Committee is made up of non-employee directors of Southern Company who have never served as executive officers of Southern Company or Gulf Power. During 2014, none of Southern Company's or Gulf Power's executive officers served on the board of directors of any entities whose directors or 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, 2015.

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	5,642,717	

Security Ownership of Management. The following tables show the number of shares of Common Stock owned by the directors, nominees, and executive officers as of December 31, 2014. 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 outstanding on December 31, 2014.

Name of Directors, Nominees, and Executive Officers	Shares Beneficially Owned (1)	Shares Beneficially Owned Include: Deferred Stock Units (2)	Shares Beneficially Owned Include: Shares Individuals Have Rights to Acquire Within 60 Days (3)
S. W. Connally, Jr.	140,553	0	131,046
Allan G. Bense	3,350	0	0
Deborah H. Calder	2,503	1,999	0
William C. Cramer, Jr.	17,460	17,460	0
Julian B. MacQueen	963	—	0
J. Mort O'Sullivan III	3,721	3,721	0
Michael T. Rehwinkel	480	0	0
Winston E. Scott	7,592	0	0
Michael L. Burroughs	40,327	0	35,557
Jim R. Fletcher	32,455	0	29,391
Richard S. Teel	85,092	0	84,451
Bentina C. Terry	81,808	0	73,991
Directors, Nominees, and Executive Officers as a group (13 people)	431,770	23,180	366,319

(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.

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. None.

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." Southern Company has a Code of Ethics as well as a Contract Guidance Manual and other formal written procurement policies and procedures that guide the purchase of goods and services, including requiring competitive bids for most transactions above $10,000 or approval based on documented business needs for sole sourcing arrangements. 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 supply chain management; 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.

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.

Southern Company owns all of Gulf Power's outstanding common stock. Gulf Power has listed only debt securities on the NYSE. Accordingly, under the rules of the NYSE, Gulf Power is exempt from most of the NYSE's listing standards relating to corporate governance. Gulf Power has voluntarily complied with certain NYSE listing standards relating to corporate governance where such compliance was deemed to be in the best interests of Gulf Power's shareholders.

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 2014 and 2013:

	2014	2013
	(in thousands)	
Gulf Power		
Audit Fees (1)	$ 1,427	$ 1,395
Audit-Related Fees	—	—
Tax Fees	—	—
All Other Fees	12	—
Total	$ 1,439	$ 1,395
Southern Power		
Audit Fees (1)	$ 1,143	$ 1,159
Audit-Related Fees	—	—
Tax Fees	—	—
All Other Fees	2	—
Total	$ 1,145	$ 1,159

(1) Includes services performed in connection with financing transactions.

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 2014 and 2013 (described in the footnotes to the table above) and related fees were approved in advance by the Southern Company Audit Committee.

[This page intentionally left blank]

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.

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, and Mississippi Power, 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, and Southern Power 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, and Mississippi Power are listed in the Index to the Financial Statement Schedules at page S-1.

(2) Exhibits:

Exhibits for Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power are listed in the Exhibit Index at page E-1.

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:
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

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.

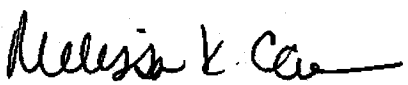
Thomas A. Fanning
Chairman, President,
Chief Executive Officer, and Director
(Principal Executive Officer)

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: 
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

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: Melissa K. Caen

(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

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, Chief Executive Officer, and Director
(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
Ralph D. Cook
David J. Cooper, Sr.
Anthony A. Joseph
Patricia M. King
James K. Lowder
Malcolm Portera
Robert D. Powers
Catherine J. Randall
C. Dowd Ritter
James H. Sanford
John Cox Webb, IV

By: Melissa K. Caen

(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

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: Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

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, Chief Executive Officer, and Director
(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
Jimmy C. Tallent
Charles K. Tarbutton
Beverly Daniel Tatum
D. Gary Thompson
Clyde C. Tuggle
Richard W. Ussery

By: Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

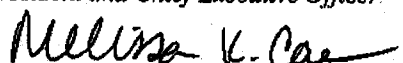
GULF POWER COMPANY

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.
President and Chief Executive Officer

By: 
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

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.

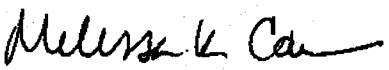
S. W. Connally, Jr.
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Richard S. Teel
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: 
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

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: G. Edison Holland, Jr.
Chairman, President, and Chief Executive Officer

By: Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

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.

G. Edison Holland, Jr.
Chairman, President, Chief Executive Officer, and Director
(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: Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

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: Oscar C. Harper IV
President and Chief Executive Officer

By: Melissa K Caen
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

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.

Oscar C. Harper IV
President, Chief Executive Officer, and Director
(Principal Executive Officer)

William C. Grantham
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: Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

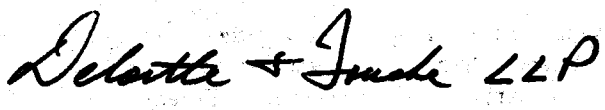
Supplemental Information to be Furnished With Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act:

No annual report, proxy statement, form of proxy or other proxy soliciting material has been sent to security holders of the registrant during the period covered by this Annual Report on Form 10-K for the fiscal year ended December 31, 2014.

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, 2014 and 2013, and for each of the three years in the period ended December 31, 2014, and the Company's internal control over financial reporting as of December 31, 2014, and have issued our report thereon dated March 2, 2015; 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.



Atlanta, Georgia
March 2, 2015

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, 2014 and 2013, and for each of the three years in the period ended December 31, 2014, and have issued our report thereon dated March 2, 2015; 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.

Deloitte & Touche LLP

Birmingham, Alabama
March 2, 2015

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, 2014 and 2013, and for each of the three years in the period ended December 31, 2014, and have issued our report thereon dated March 2, 2015; 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.

Deloitte & Touche LLP

Atlanta, Georgia
March 2, 2015

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, 2014 and 2013, and for each of the three years in the period ended December 31, 2014, and have issued our report thereon dated March 2, 2015; 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.

Deloitte & Touche LLP

Atlanta, Georgia
March 2, 2015

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, 2014 and 2013, and for each of the three years in the period ended December 31, 2014, and have issued our report thereon dated March 2, 2015; 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.

Deloitte & Touche LLP

Atlanta, Georgia
March 2, 2015

INDEX TO FINANCIAL STATEMENT SCHEDULES

	Page
Schedule II	
Valuation and Qualifying Accounts and Reserves 2014, 2013, and 2012	
The Southern Company and Subsidiary Companies	S-2
Alabama Power Company	S-3
Georgia Power Company	S-4
Gulf Power Company	S-5
Mississippi Power Company	S-6

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, 2014. 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, 2014, 2013, AND 2012
(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					
2014	$ 17,855	$ 43,537	$ —	$ 43,139	$ 18,253
2013	16,984	36,788	—	35,917	17,855
2012	26,155	35,305	—	44,476	16,984

(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, 2014, 2013, AND 2012
(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					
2014	$ 8,350	$ 14,309	$ —	$ 13,516	$ 9,143
2013	8,450	12,327	—	12,427	8,350
2012	9,856	10,537	—	11,943	8,450

(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, 2014, 2013, AND 2012
(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					
2014	$ 5,074	$ 24,141	$ —	$ 23,139	$ 6,076
2013	6,259	18,362	—	19,547	5,074
2012	13,038	20,995	—	27,774	6,259

(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, 2014, 2013, AND 2012
(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					
2014	$ 1,131	$ 4,304	$ —	$ 3,348	$ 2,087
2013	1,490	1,900	—	2,259	1,131
2012	1,962	2,611	—	3,083	1,490

(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, 2014, 2013, AND 2012
(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					
2014	$ 3,018	$ 562	$ —	$ 2,755	$ 825
2013	373	3,757	—	1,112	3,018
2012	547	628	—	802	373

(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.

(3) Articles of Incorporation and By-Laws

Southern Company

(a) 1 — Composite Certificate of Incorporation of Southern Company, reflecting all amendments thereto through May 27, 2010. (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, and in Form 8-K dated May 26, 2010, File No. 1-3526, as Exhibit 3.1.)

(a) 2 — By-laws of Southern Company as amended effective February 11, 2013, and as presently in effect. (Designated in Form 8-K dated February 11, 2013, File No. 1-3526, as Exhibit 3.1.)

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 Alabama Power's 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 Alabama Power's Form 10-K for the year ended December 31, 2000, File No. 1-3164, as Exhibit 3(b)2, in Alabama Power's 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 Alabama Power's 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 Alabama Power's 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 Alabama Power's 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 Georgia Power's 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 Georgia Power's Form 10-K for the year ended December 31, 1997, File No. 1-6468, as Exhibit 3(c)2, in Georgia Power's 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 May 20, 2009, and as presently in effect. (Designated in Form 8-K dated May 20, 2009, File No. 1-6468, as Exhibit 3(c)2.)

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 Mississippi Power's Form 10-K for the year ended December 31, 1997, File No. 001-11229, as Exhibit 3(e)2, in Mississippi Power's 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 February 28, 2001, and as presently in effect. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2001, File No. 001-11229, as Exhibit 3(e)2.)

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.)

(4) Instruments Describing Rights of Security Holders, Including Indentures

With respect to each of Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power Company, 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 August 22, 2014. (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, and in Form 8-K dated August 19, 2014, File No. 1-3526, as Exhibits 4.2(a) and 4.2(b).)

Alabama Power

(b) 1 — Subordinated Note Indenture dated as of January 1, 1997, between Alabama Power and 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 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 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 supplemental thereto through August 26, 2014. (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, and in Form 8-K dated August 20, 2014, 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 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 supplemental thereto through August 16, 2013. (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), and in Form 8-K dated August 12, 2013, File No. 1-6468, as Exhibit 4.2.)

(c) 2 — Loan Guarantee Agreement between Georgia Power and the DOE dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.1.)

(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 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 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).)

Southern Power

(f) 1 — Senior Note Indenture dated as of June 1, 2002, between Southern Power Company and The Bank of New York Mellon (formerly known as The Bank of New York), as Trustee, and indentures supplemental thereto through July 16, 2013. (Designated in Registration No. 333-98553 as Exhibits 4.1 and 4.2 and in Southern Power Company's 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, and in Form 8-K dated July 10, 2013, File No. 333-98553, as Exhibit 4.4.)

(10) Material Contracts

Southern Company

\# (a) 1 — Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. (Designated in Southern Company's 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 Southern Company's 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. (Designated in Southern Company's Form 10-K for the year ended December 31, 2007, File No. 1-3526, as Exhibit 10(a)3.)

\# (a) 4 — Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)4 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)5.)

#	(a)	5	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)6 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)(8).)
#	(a)	6	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)7 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)10.)
#	(a)	7	—	Retention and Restricted Stock Unit Award Agreement by and between Southern Company and Charles D. McCrary effective May 22, 2012. (Designated in Southern Company's Form 10-Q for the quarter ended June 30, 2012, File No. 1-3526, as Exhibit 10(a)1.)
#	(a)	8	—	Amendment to Retention and Restricted Stock Unit Award Agreement by and between Southern Company and Charles D. McCrary effective February 10, 2014. (Designated in Southern Company's Form 10-K for the year ended December 31, 2013, File No. 1-3526, as Exhibit 10(a)9.)
#	(a)	9	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. (Designated in Form 8-K dated December 31, 2008, File No. 1-3526, as Exhibit 10.1.)
#	(a)	10	—	Southern Company Deferred Compensation Trust Agreement as 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, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)103 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)16.)
#	(a)	11	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of 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 Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)104 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)18.)
#	(a)	12	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, 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 Southern Company's Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)92 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)20.)
#	(a)	13	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)23, in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)22, and in Southern Company's Form 10-K for the year ended December 31, 2010, File No. 1-3526, as Exhibit 10(a)16.)
#	(a)	14	—	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 Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)24 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)24.)
# *	(a)	15	—	Base Salaries of Named Executive Officers.
#	(a)	16	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Form 8-K dated February 10, 2014, File No. 1-3526, as Exhibit 10.1.)
# *	(a)	17	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan.
#	(a)	18	—	Retention and Restricted Stock Unit Award Agreement between Southern Nuclear and Stephen E. Kuczynski effective as of July 11, 2011. (Designated in Form 10-Q for the quarter ended March 31, 2013, File No. 1-3526, as Exhibit 10(a)3).)

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 as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(b)	5	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)5 herein.
#	(b)	6	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. 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)14 herein.
#	(b)	8	—	Deferred Compensation Plan for Directors of Alabama Power Company, Amended and Restated effective January 1, 2008. (Designated in Alabama Power's Form 10-Q for the quarter ended June 30, 2008, File No. 1-3164, as Exhibit 10(b)1.)
#	(b)	9	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)9 herein.
#	(b)	10	—	Southern Company Deferred Compensation Trust Agreement as 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, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.
#	(b)	11	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of 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)11 herein.
#	(b)	12	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, 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)12 herein.
#	(b)	13	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See Exhibit 10(a)13 herein.
# *	(b)	14	—	Base Salaries of Named Executive Officers.
#	(b)	15	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Alabama Power's Form 10-Q for the quarter ended June 30, 2010, File No. 1-3164, as Exhibit 10(b) 1.)
#	(b)	16	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)17 herein.
#	(b)	17	—	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 Alabama Power's Form 10-Q for the quarter ended September 30, 2010, File No. 1-3164, as Exhibit 10(b)2.)
#	(b)	18	—	Retention and Restricted Stock Unit Award Agreement by and between Southern Company and Charles D. McCrary effective May 22, 2012. See Exhibit 10(a)7 herein.
#	(b)	19	—	Amendment to Retention and Restricted Stock Unit Award Agreement by and between Southern Company and Charles D. McCrary effective February 10, 2014. See Exhibit 10(a) 8 herein.

#	(b)	20	—	Retention Award Agreement between Alabama Power and Steven R. Spencer effective July 15, 2013. (Designated in Form 10-Q for the quarter ended September 30, 2013, File No. 1-3164, as Exhibit 10(b)1.)
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 Georgia Power's 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 Georgia Power's 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 Georgia Power's 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 as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(c)	8	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)5 herein.
#	(c)	9	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. 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)14 herein.
#	(c)	11	—	Deferred Compensation Plan For Directors of Georgia Power Company, Amended and Restated Effective January 1, 2008. (Designated in Form 10-K for the year ended December 31, 2007, File No. 1-6468, as Exhibit 10(c)12.)
#	(c)	12	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)9 herein.
#	(c)	13	—	Southern Company Deferred Compensation Trust Agreement as 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, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.
#	(c)	14	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of 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)11 herein.
#	(c)	15	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, 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)12 herein.
#	(c)	16	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See Exhibit 10(a)13 herein.
# *	(c)	17	—	Base Salaries of Named Executive Officers.
#	(c)	18	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Georgia Power's Form 10-K for the year ended December 31, 2009, File No. 1-6468, as Exhibit 10 (c)26.)

	(c)	19	—	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, and Amendment No. 6 thereto dated as of January 23, 2014. (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 Georgia Power's Form 10-Q for the quarter ended March 31, 2010, File No. 1-6468, as Exhibits 10(c)1 and 10(c)2, in Georgia Power's Form 10-Q for the quarter ended June 30, 2011, File No. 1-6468, as Exhibit 10(c)2, in Georgia Power's Form 10-Q for the quarter ended March 31, 2012, File No. 1-6468, as Exhibit 10(c)2, and in Georgia Power's Form 10-Q for the quarter ended March 31, 2014, File No. 1-6468, as Exhibit 10(c)2.)
#	(c)	20	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)17 herein.
#	(c)	21	—	Retention Award Agreement and Amendment thereto between Southern Nuclear and Joseph A. Miller, effective January 1, 2013. (Designated in Form 10-K for the year ended December 31, 2012, File No. 1-6468, as Exhibits 10(c)24 and 10(c)25.)

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 as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(d)	5	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(d)	6	—	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)14 herein.
#	(d)	7	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. 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. (Designated in Gulf Power's Form 10-Q for the quarter ended March 31, 2008, File No. 0-2429, as Exhibit 10(d)1.)
#	(d)	9	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)9 herein.
#	(d)	10	—	Southern Company Deferred Compensation Trust Agreement as 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, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.
#	(d)	11	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of 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)11 herein.

#	(d)	12	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, 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)12 herein.
#	(d)	13	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See Exhibit 10(a)13 herein.
# *	(d)	14	—	Base Salaries of Named Executive Officers.
#	(d)	15	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Gulf Power's Form 10-Q for the quarter ended June 30, 2010, File No. 001-31737, as Exhibit 10 (d)1.)
#	(d)	16	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)17 herein.
#	(d)	17	—	Deferred Compensation Agreement between Southern Company, Georgia Power, Gulf Power, and Southern Nuclear and Bentina C. Terry dated August 1, 2010. (Designated in Gulf Power's Form 10-Q for the quarter ended September 30, 2010, File No. 001-31737, as Exhibit 10(d)2.)
#	(d)	18	—	Separation and Release Agreement between P. Bernard Jacob and Gulf Power effective May 2, 2014. (Designated in Gulf Power's Form 10-Q for the quarter ended June 30, 2014, File No. 001-31737, as Exhibit 10(d)1.)

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 Mississippi Power's Form 10-K for the year ended December 31, 1981, File No. 001-11229, as Exhibit 10(f), in Mississippi Power's Form 10-K for the year ended December 31, 1982, File No. 001-11229, as Exhibit 10(f)(2), and in Mississippi Power's 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 as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(e)	6	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. 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)14 herein.
#	(e)	8	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. 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. (Designated in Mississippi Power's Form 10-Q for the quarter ended March 31, 2008, File No. 001-11229 as Exhibit 10(e)1.)
#	(e)	10	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)9 herein.
#	(e)	11	—	Southern Company Deferred Compensation Trust Agreement as 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, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.

#	(e)	12	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of 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)11 herein.
#	(e)	13	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, 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)12 herein.
#	(e)	14	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See Exhibit 10(a)13 herein.
# *	(e)	15	—	Base Salaries of Named Executive Officers.
#	(e)	16	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2009, File No. 001-11229, as Exhibit 10(e)22.)
	(e)	17	—	Cooperative Agreement between the DOE and SCS dated as of December 12, 2008. (Designated in Mississippi Power's 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)	18	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)17 herein.
#	(e)	19	—	Consulting Agreement between Mississippi Power and Edward Day, VI effective May 20, 2013. (Designated in Form 10-Q for the quarter ended June 30, 2013, File No. 001-11229, as Exhibit 10(e)1.)
#	(e)	20	—	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.)

Southern Power

(f)	1	—	Service contract dated as of January 1, 2001, between SCS and Southern Power Company. (Designated in Southern Company's 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.

(14) Code of Ethics

Southern Company

(a)	—	The Southern Company Code of Ethics. (Designated in Southern Company's Form 10-K for the year ended December 31, 2013, File No. 1-3526, as Exhibit 14(a).)

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.

(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.

(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.

Mississippi Power

* (e) 1 — Consent of Deloitte & Touche LLP.

Southern Power

* (f) 1 — Consent of Deloitte & Touche 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.

(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.

(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.

(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

[This page intentionally left blank]

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

FORM 10-Q

☑ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2015
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 35203 (205) 257-1000	63-0004250
1-6468	**Georgia Power Company** (A Georgia Corporation) 241 Ralph McGill Boulevard, N.E. Atlanta, Georgia 30308 (404) 506-6526	58-0257110
001-31737	**Gulf Power Company** (A Florida Corporation) One Energy Place Pensacola, Florida 32520 (850) 444-6111	59-0276810
001-11229	**Mississippi Power Company** (A Mississippi Corporation) 2992 West Beach Boulevard Gulfport, Mississippi 39501 (228) 864-1211	64-0205820
333-98553	**Southern Power Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-2598670

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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	

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

Registrant	Description of Common Stock	Shares Outstanding at June 30, 2015
The Southern Company	**Par Value $5 Per Share**	**908,424,808**
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**	**5,642,717**
Mississippi Power Company	**Without Par Value**	**1,121,000**
Southern Power Company	**Par Value $0.01 Per Share**	**1,000**

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

INDEX TO QUARTERLY REPORT ON FORM 10-Q
June 30, 2015

		Page Number
DEFINITIONS		5
CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION		7
	PART I—FINANCIAL INFORMATION	
Item 1.	Financial Statements (Unaudited)	
Item 2.	Management's Discussion and Analysis of Financial Condition and Results of Operations	
	The Southern Company and Subsidiary Companies	
	Condensed Consolidated Statements of Income	10
	Condensed Consolidated Statements of Comprehensive Income	11
	Condensed Consolidated Statements of Cash Flows	12
	Condensed Consolidated Balance Sheets	13
	Management's Discussion and Analysis of Financial Condition and Results of Operations	15
	Alabama Power Company	
	Condensed Statements of Income	40
	Condensed Statements of Comprehensive Income	40
	Condensed Statements of Cash Flows	41
	Condensed Balance Sheets	42
	Management's Discussion and Analysis of Financial Condition and Results of Operations	44
	Georgia Power Company	
	Condensed Statements of Income	60
	Condensed Statements of Comprehensive Income	60
	Condensed Statements of Cash Flows	61
	Condensed Balance Sheets	62
	Management's Discussion and Analysis of Financial Condition and Results of Operations	64
	Gulf Power Company	
	Condensed Statements of Income	82
	Condensed Statements of Comprehensive Income	82
	Condensed Statements of Cash Flows	83
	Condensed Balance Sheets	84
	Management's Discussion and Analysis of Financial Condition and Results of Operations	86
	Mississippi Power Company	
	Condensed Statements of Operations	102
	Condensed Statements of Comprehensive Income (Loss)	102
	Condensed Statements of Cash Flows	103
	Condensed Balance Sheets	104
	Management's Discussion and Analysis of Financial Condition and Results of Operations	106
	Southern Power Company and Subsidiary Companies	
	Condensed Consolidated Statements of Income	134
	Condensed Consolidated Statements of Comprehensive Income	134
	Condensed Consolidated Statements of Cash Flows	135
	Condensed Consolidated Balance Sheets	136
	Management's Discussion and Analysis of Financial Condition and Results of Operations	138
	Notes to the Condensed Financial Statements	149
Item 3.	Quantitative and Qualitative Disclosures about Market Risk	38
Item 4.	Controls and Procedures	38

INDEX TO QUARTERLY REPORT ON FORM 10-Q
June 30, 2015

		Page Number
	PART II—OTHER INFORMATION	
Item 1.	Legal Proceedings	195
Item 1A.	Risk Factors	195
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	195
Item 3.	Defaults Upon Senior Securities	Inapplicable
Item 4.	Mine Safety Disclosures	Inapplicable
Item 5.	Other Information	Inapplicable
Item 6.	Exhibits	196
	Signatures	200

DEFINITIONS

Term	Meaning
2012 MPSC CPCN Order	A detailed order issued by the Mississippi PSC in April 2012 confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC
2013 ARP	Alternative Rate Plan approved by the Georgia PSC for Georgia Power for the years 2014 through 2016
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ASC	Accounting Standards Codification
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
Contractor	Westinghouse and CB&I Stone & Webster, Inc. (formerly known as Stone & Webster, Inc.), a subsidiary of The Shaw Group Inc., which was acquired by Chicago Bridge & Iron Company N.V.
CO_2	Carbon dioxide
CPCN	Certificate of public convenience and necessity
CWIP	Construction work in progress
DOE	U.S. Department of Energy
ECO Plan	Mississippi Power's Environmental Compliance Overview Plan
Eligible Project Costs	Certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Title XVII Loan Guarantee Program
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FFB	Federal Financing Bank
Fitch	Fitch Ratings, Inc.
Form 10-K	Combined Annual Report on Form 10-K of Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power for the year ended December 31, 2014
GAAP	Generally accepted accounting principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IGCC	Integrated coal gasification combined cycle
IIC	Intercompany interchange contract
Internal Revenue Code	Internal Revenue Code of 1986, as amended
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
MATS rule	Mercury and Air Toxics Standards rule
Mirror CWIP	A regulatory liability account for use in mitigating future rate impacts for Mississippi Power customers
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt

DEFINITIONS
(continued)

Term	Meaning
NCCR	Georgia Power's Nuclear Construction Cost Recovery
NRC	U.S. Nuclear Regulatory Commission
OCI	Other comprehensive income
PEP	Mississippi Power's Performance Evaluation Plan
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 operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
Rate CNP	Alabama Power's Rate Certificated New Plant
Rate CNP Compliance	Alabama Power's Rate Certificated New Plant Compliance
Rate CNP Environmental	Alabama Power's Rate Certificated New Plant Environmental
Rate CNP PPA	Alabama Power's Rate Certificated New Plant Power Purchase Agreement
registrants	Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power Company
ROE	Return on equity
S&P	Standard and Poor's Ratings Services, a division of The McGraw Hill Companies, Inc.
scrubber	Flue gas desulfurization system
SEC	U.S. Securities and Exchange Commission
SMEPA	South Mississippi Electric Power Association
Southern Company	The Southern Company
Southern Company system	Southern Company, the traditional operating companies, Southern Power, Southern Electric Generating Company, Southern Nuclear, Southern Company Services, Inc. (the Southern Company system service company), Southern Communications Services, Inc., and other subsidiaries
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power
Vogtle Owners	Georgia Power, Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners
Westinghouse	Westinghouse Electric Company LLC

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, the strategic goals for the wholesale business, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, completion dates of acquisitions, construction projects, and changing fuel sources, filings with state and federal regulatory authorities, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, CCR, and emissions of sulfur, nitrogen, CO_2, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, and IRS and state tax audits;
- 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, 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, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction 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 Southern Company's employee and retiree benefit plans and the Southern Company system's 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;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions and related legal proceedings involving the commercial parties;
- actions related to cost recovery for the Kemper IGCC, including actions relating to Mississippi PSC approval of a rate recovery plan, including Mississippi Power's request for interim rates, proposed securitization, the ability to utilize bonus depreciation, which currently requires that assets be placed in service in 2015, and satisfaction of requirements to utilize ITCs and grants;
- the ultimate impact of the termination of the proposed sale of an interest in the Kemper IGCC to SMEPA;
- Mississippi PSC review of the prudence of Kemper IGCC costs;

- the ultimate impact of the 2015 decision of the Mississippi Supreme Court, the Mississippi PSC's order implementing such decision, and any further related legal or regulatory proceedings;
- the ability to successfully operate the electric utilities' generating, transmission, and distribution 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 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 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 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 subsidiaries to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Southern Company system'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 registrants from time to time with the SEC.

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

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES

[This page intentionally left blank]

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	**2015**	2014
	(in millions)		*(in millions)*	
Operating Revenues:				
Retail revenues	**$ 3,714**	$ 3,770	**$ 7,256**	$ 7,628
Wholesale revenues	**448**	515	**915**	1,119
Other electric revenues	**162**	169	**325**	334
Other revenues	**13**	13	**24**	30
Total operating revenues	**4,337**	4,467	**8,520**	9,111
Operating Expenses:				
Fuel	**1,200**	1,462	**2,412**	3,109
Purchased power	**171**	133	**315**	320
Other operations and maintenance	**1,100**	1,019	**2,222**	2,005
Depreciation and amortization	**500**	504	**987**	1,001
Taxes other than income taxes	**245**	246	**497**	493
Estimated loss on Kemper IGCC	**23**	—	**32**	380
Total operating expenses	**3,239**	3,364	**6,465**	7,308
Operating Income	**1,098**	1,103	**2,055**	1,803
Other Income and (Expense):				
Allowance for equity funds used during construction	**39**	62	**102**	119
Interest expense, net of amounts capitalized	**(180)**	(210)	**(393)**	(416)
Other income (expense), net	**(12)**	(6)	**(19)**	(13)
Total other income and (expense)	**(153)**	(154)	**(310)**	(310)
Earnings Before Income Taxes	**945**	949	**1,745**	1,493
Income taxes	**302**	321	**576**	497
Consolidated Net Income	**643**	628	**1,169**	996
Dividends on Preferred and Preference Stock of Subsidiaries	**14**	17	**31**	34
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	**$ 629**	$ 611	**$ 1,138**	$ 962
Common Stock Data:				
Earnings per share (EPS) —				
Basic EPS	**$ 0.69**	$ 0.68	**$ 1.25**	$ 1.08
Diluted EPS	**$ 0.69**	$ 0.68	**$ 1.25**	$ 1.07
Average number of shares of common stock outstanding (in millions)				
Basic	**909**	895	**910**	892
Diluted	**912**	899	**914**	896
Cash dividends paid per share of common stock	**$ 0.5425**	$ 0.5250	**$ 1.0675**	$ 1.0325

The accompanying notes as they relate to Southern Company are an integral part of these consolidated financial statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	**2015**	2014
	(in millions)		*(in millions)*	
Consolidated Net Income	**$ 643**	$ 628	**$ 1,169**	$ 996
Other comprehensive income (loss):				
Qualifying hedges:				
Changes in fair value, net of tax of $12, $-, $1, and $-, respectively	**19**	—	**1**	—
Reclassification adjustment for amounts included in net income, net of tax of $1, $-, $2, and $2, respectively	**2**	1	**3**	2
Pension and other post retirement benefit plans:				
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, $2, and $1, respectively	**1**	1	**3**	2
Total other comprehensive income (loss)	**22**	2	**7**	4
Dividends on preferred and preference stock of subsidiaries	**(14)**	(17)	**(31)**	(34)
Comprehensive Income	**$ 651**	$ 613	**$ 1,145**	$ 966

The accompanying notes as they relate to Southern Company are an integral part of these consolidated financial statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Six Months Ended June 30,	
	2015	2014
	(in millions)	
Operating Activities:		
Consolidated net income	**$ 1,169**	$ 996
Adjustments to reconcile consolidated net income to net cash provided from operating activities —		
Depreciation and amortization, total	**1,171**	1,182
Deferred income taxes	**783**	46
Allowance for equity funds used during construction	**(102)**	(119)
Stock based compensation expense	**66**	40
Estimated loss on Kemper IGCC	**32**	380
Income taxes receivable, non-current	**(444)**	—
Other, net	**(6)**	23
Changes in certain current assets and liabilities —		
-Receivables	**(158)**	(579)
-Fossil fuel stock	**136**	419
-Materials and supplies	**(21)**	(20)
-Other current assets	**(78)**	(88)
-Accounts payable	**(311)**	(231)
-Accrued taxes	**(60)**	72
-Accrued compensation	**(269)**	(40)
-Mirror CWIP	**82**	67
-Other current liabilities	**117**	(78)
Net cash provided from operating activities	**2,107**	2,070
Investing Activities:		
Property additions	**(2,647)**	(2,692)
Nuclear decommissioning trust fund purchases	**(933)**	(445)
Nuclear decommissioning trust fund sales	**928**	443
Cost of removal, net of salvage	**(87)**	(54)
Change in construction payables, net	**56**	89
Prepaid long-term service agreement	**(110)**	(93)
Other investing activities	**27**	(17)
Net cash used for investing activities	**(2,766)**	(2,769)
Financing Activities:		
Increase in notes payable, net	**184**	339
Proceeds —		
Long-term debt issuances	**3,075**	1,314
Interest-bearing refundable deposit	**—**	75
Common stock issuances	**116**	318
Short-term borrowings	**320**	—
Redemptions and repurchases—		
Long-term debt	**(939)**	(431)
Interest-bearing refundable deposits	**(275)**	—
Preferred and preference stock	**(412)**	—
Common stock	**(115)**	(5)
Short-term borrowings	**(250)**	—
Payment of common stock dividends	**(972)**	(920)
Payment of dividends on preferred and preference stock of subsidiaries	**(36)**	(34)
Other financing activities	**66**	(33)
Net cash provided from financing activities	**762**	623
Net Change in Cash and Cash Equivalents	**103**	(76)
Cash and Cash Equivalents at Beginning of Period	**710**	659
Cash and Cash Equivalents at End of Period	**$ 813**	$ 583
Supplemental Cash Flow Information:		
Cash paid (received) during the period for --		
Interest (net of $57 and $47 capitalized for 2015 and 2014, respectively)	**$ 374**	$ 365
Income taxes, net	**(16)**	212
Noncash transactions — Accrued property additions at end of period	**345**	509

The accompanying notes as they relate to Southern Company are an integral part of these consolidated financial statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Assets	At June 30, 2015	At December 31, 2014
	(in millions)	
Current Assets:		
Cash and cash equivalents	$ 813	$ 710
Receivables —		
Customer accounts receivable	1,312	1,090
Unbilled revenues	579	432
Under recovered regulatory clause revenues	173	136
Other accounts and notes receivable	209	307
Accumulated provision for uncollectible accounts	(17)	(18)
Fossil fuel stock, at average cost	795	930
Materials and supplies, at average cost	1,043	1,039
Vacation pay	177	177
Prepaid expenses	564	665
Deferred income taxes, current	499	506
Other regulatory assets, current	382	346
Other current assets	76	50
Total current assets	6,605	6,370
Property, Plant, and Equipment:		
In service	71,462	70,013
Less accumulated depreciation	23,918	24,059
Plant in service, net of depreciation	47,544	45,954
Other utility plant, net	87	211
Nuclear fuel, at amortized cost	889	911
Construction work in progress	8,487	7,792
Total property, plant, and equipment	57,007	54,868
Other Property and Investments:		
Nuclear decommissioning trusts, at fair value	1,572	1,546
Leveraged leases	751	743
Miscellaneous property and investments	232	203
Total other property and investments	2,555	2,492
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	1,533	1,510
Unamortized debt issuance expense	208	202
Unamortized loss on reacquired debt	234	243
Other regulatory assets, deferred	4,763	4,334
Income taxes receivable, non-current	444	—
Other deferred charges and assets	832	904
Total deferred charges and other assets	8,014	7,193
Total Assets	$ 74,181	$ 70,923

The accompanying notes as they relate to Southern Company are an integral part of these consolidated financial statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholders' Equity	At June 30, 2015	At December 31, 2014
	(in millions)	
Current Liabilities:		
Securities due within one year	$ 3,643	$ 3,333
Interest-bearing refundable deposits	—	275
Notes payable	1,057	803
Accounts payable	1,395	1,593
Customer deposits	398	390
Accrued taxes —		
Accrued income taxes	12	151
Other accrued taxes	391	487
Accrued interest	241	295
Accrued vacation pay	222	223
Accrued compensation	305	576
Mirror CWIP	353	271
Other current liabilities	677	570
Total current liabilities	8,694	8,967
Long-term Debt	22,674	20,841
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	12,187	11,568
Deferred credits related to income taxes	186	192
Accumulated deferred investment tax credits	1,290	1,208
Employee benefit obligations	2,375	2,432
Asset retirement obligations	2,860	2,168
Other cost of removal obligations	1,206	1,215
Other regulatory liabilities, deferred	408	398
Other deferred credits and liabilities	996	594
Total deferred credits and other liabilities	21,508	19,775
Total Liabilities	52,876	49,583
Redeemable Preferred Stock of Subsidiaries	118	375
Redeemable Noncontrolling Interest	41	39
Stockholders' Equity:		
Common Stockholders' Equity:		
Common stock, par value $5 per share —		
Authorized — 1.5 billion shares		
Issued — June 30, 2015: 912 million shares		
— December 31, 2014: 909 million shares		
Treasury — June 30, 2015: 3.3 million shares		
— December 31, 2014: 0.7 million shares		
Par value	4,555	4,539
Paid-in capital	6,123	5,955
Treasury, at cost	(142)	(26)
Retained earnings	9,767	9,609
Accumulated other comprehensive loss	(121)	(128)
Total Common Stockholders' Equity	20,182	19,949
Preferred and Preference Stock of Subsidiaries	609	756
Noncontrolling Interest	355	221
Total Stockholders' Equity	21,146	20,926
Total Liabilities and Stockholders' Equity	$ 74,181	$ 70,923

The accompanying notes as they relate to Southern Company are an integral part of these consolidated financial statements.

OVERVIEW

Southern Company is a holding company that owns all of the common stock of the traditional operating companies and Southern Power Company and owns other direct and indirect subsidiaries. Discussion of the results of operations is focused on the Southern Company system's primary business of electricity sales by the traditional operating companies and Southern Power. The four traditional operating companies 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's other business activities include investments in leveraged lease projects and telecommunications. For additional information on these businesses, see BUSINESS – "The Southern Company System – Traditional Operating Companies," " – Southern Power," and " – Other Businesses" in Item 1 of the Form 10-K.

In addition, 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 RESULTS OF OPERATIONS – "Estimated Loss on Kemper IGCC," FUTURE EARNINGS POTENTIAL – "Construction Program," and Note (B) to the Condensed Financial Statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" herein for additional information. For information about Southern Power's acquisitions and construction of renewable energy facilities, see Note (I) to the Condensed Financial Statements herein.

Southern Company continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, execution of major construction projects, and earnings per share. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Key Performance Indicators" of Southern Company in Item 7 of the Form 10-K.

RESULTS OF OPERATIONS

Net Income

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$18	2.9	$176	18.3

Southern Company's second quarter 2015 net income after dividends on preferred and preference stock of subsidiaries was $629 million ($0.69 per share) compared to $611 million ($0.68 per share) for the second quarter 2014. The increase was primarily due to an increase in retail revenues resulting from retail base rate increases and warmer weather in the second quarter 2015 as compared to the corresponding period in 2014, partially offset by the correction of an error affecting billings to certain Georgia Power commercial and industrial customers. Also contributing to the increase were state income tax benefits realized and a decrease in interest expense. The increase in net income was partially offset by increases in non-fuel operations and maintenance expenses and a decrease in AFUDC equity.

Southern Company's year-to-date 2015 net income after dividends on preferred and preference stock of subsidiaries was $1.1 billion ($1.25 per share) compared to $962 million ($1.08 per share) for the corresponding period in 2014. The increase was primarily the result of lower pre-tax charges of $32 million ($20 million after tax) recorded in 2015 compared to a pre-tax charge of $380 million ($235 million after tax) recorded in the corresponding period in 2014 for revisions of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper

IGCC, as well as an increase in retail base rates. The increase in net income was partially offset by increases in non-fuel operations and maintenance expenses.

Retail Revenues

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(56)	(1.5)	$(372)	(4.9)

In the second quarter 2015, retail revenues were $3.7 billion compared to $3.8 billion for the corresponding period in 2014. For year-to-date 2015, retail revenues were $7.3 billion compared to $7.6 billion for the corresponding period in 2014.

Details of the changes in retail revenues were as follows:

	Second Quarter 2015		Year-to-Date 2015	
	(in millions)	*(% change)*	*(in millions)*	*(% change)*
Retail – prior year	$ 3,770		$ 7,628	
Estimated change resulting from –				
Rates and pricing	30	0.8	107	1.4
Sales growth	23	0.6	41	0.5
Weather	46	1.2	8	0.1
Fuel and other cost recovery	(155)	(4.1)	(528)	(6.9)
Retail – current year	$ 3,714	(1.5)%	$ 7,256	(4.9)%

Revenues associated with changes in rates and pricing increased in the second quarter and year-to-date 2015 when compared to the corresponding periods in 2014 primarily due to increased revenues at Alabama Power associated with an increase in rates under rate stabilization and equalization (Rate RSE) and at Georgia Power related to base tariff increases approved under the 2013 ARP and increases in collections for financing costs related to the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff, all effective January 1, 2015. The increase was partially offset by the 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 (A) to the Condensed Financial Statements herein and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Alabama Power – Rate RSE" and "Retail Regulatory Matters – Georgia Power – Rate Plans" in Item 8 of the Form 10-K for additional information.

Revenues attributable to changes in sales increased in the second quarter 2015 when compared to the corresponding period in 2014. Weather-adjusted residential KWH sales and weather-adjusted commercial KWH sales increased 1.2% and 0.7%, respectively, in the second quarter 2015, both as a result of customer growth. Industrial KWH sales increased 0.2% in the second quarter 2015 primarily due to increased sales in the non-manufacturing, transportation, and pipeline sectors, partially offset by decreased sales in the primary metals, chemicals, and paper sectors.

Revenues attributable to changes in sales increased for year-to-date 2015 when compared to the corresponding period in 2014. Industrial KWH sales increased 1.1% for year-to-date 2015 primarily due to increased sales in the non-manufacturing, transportation, pipeline, and petroleum sectors, partially offset by decreased sales in the primary metals and chemicals sectors. Weather-adjusted commercial KWH sales increased 0.7% for year-to-date 2015 primarily due to customer growth. Weather-adjusted residential KWH sales increased 0.7% for year-to-date 2015 as a result of customer growth, partially offset by decreased customer usage.

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 discussed above reflect an adjustment to the estimated allocation of Mississippi Power's unbilled second quarter and year-to-date 2014 KWH sales among customer classes that is consistent with the actual allocation in 2015. Without

this adjustment, second quarter 2015 weather-adjusted residential sales increased 1.4%, weather-adjusted commercial sales increased 0.5%, and industrial KWH sales increased 0.1% as compared to the corresponding period in 2014. Also, without this adjustment, year-to-date 2015 weather-adjusted residential sales increased 0.6%, weather-adjusted commercial sales increased 0.4%, and industrial KWH sales increased 1.0% as compared to the corresponding period in 2014.

Fuel and other cost recovery revenues decreased $155 million and $528 million in the second quarter and year-to-date 2015, respectively, when compared to the corresponding periods in 2014 primarily due to a decrease in fuel prices.

Electric rates for the traditional 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 purchased power costs, and do not affect net income. The traditional operating companies may also have one or more regulatory mechanisms to recover other costs such as environmental and other compliance costs, storm damage, new plants, and PPAs.

Wholesale Revenues

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(67)	(13.0)	$(204)	(18.2)

Wholesale revenues consist of PPAs primarily with investor-owned utilities and electric cooperatives and short-term opportunity sales. Wholesale revenues from PPAs (other than solar PPAs) have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and 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 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. Wholesale revenues at Mississippi Power include FERC-regulated municipal and rural association sales as well as market-based sales. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Southern Company system's variable cost to produce the energy.

In the second quarter 2015, wholesale revenues were $448 million compared to $515 million for the corresponding period in 2014 related to a $44 million decrease in energy revenues and a $23 million decrease in capacity revenues. For year-to-date 2015, wholesale revenues were $915 million compared to $1.1 billion for the corresponding period in 2014 related to a $162 million decrease in energy revenues and a $42 million decrease in capacity revenues. The decreases in energy revenues were primarily related to lower fuel costs, partially offset by increases in energy revenues from new solar 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.

Fuel and Purchased Power Expenses

	Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
	(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
Fuel	$ (262)	(17.9)	$ (697)	(22.4)
Purchased power	38	28.6	(5)	(1.6)
Total fuel and purchased power expenses	$ (224)		$ (702)	

In the second quarter 2015, total fuel and purchased power expenses were $1.4 billion compared to $1.6 billion for the corresponding period in 2014. The decrease was primarily the result of a $337 million decrease in the average cost of fuel and purchased power primarily due to lower coal and natural gas prices, partially offset by a $113 million increase in the volume of KWHs generated and purchased primarily due to increased demand resulting from warmer weather in the second quarter 2015 as compared to the corresponding period in 2014.

For year-to-date 2015, total fuel and purchased power expenses were $2.7 billion compared to $3.4 billion for the corresponding period in 2014. The decrease was primarily the result of a $792 million decrease in the average cost of fuel and purchased power primarily due to lower coal and natural gas prices, partially offset by a $90 million increase in the volume of KWHs generated and purchased.

Fuel and purchased power energy transactions at the traditional operating companies are generally offset by fuel revenues and do not have a significant impact on net income. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Retail 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.

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

	Second Quarter 2015	Second Quarter 2014	**Year-to-Date 2015**	Year-to-Date 2014
Total generation *(billions of KWHs)*	**46**	47	**92**	94
Total purchased power *(billions of KWHs)*	**4**	2	**6**	5
Sources of generation *(percent)* —				
Coal	**39**	44	**36**	45
Nuclear	**15**	17	**16**	16
Gas	**42**	36	**44**	35
Hydro	**3**	3	**3**	4
Renewables	**1**	—	**1**	—
Cost of fuel, generated *(cents per net KWH)* —				
Coal	**3.37**	3.79	**3.52**	4.00
Nuclear	**0.84**	0.89	**0.75**	0.89
Gas	**2.76**	3.82	**2.73**	4.00
Average cost of fuel, generated *(cents per net KWH)*	**2.70**	3.28	**2.70**	3.46
Average cost of purchased power *(cents per net KWH)*(*)	**5.63**	7.41	**6.26**	8.20

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

Fuel

In the second quarter 2015, fuel expense was $1.2 billion compared to $1.5 billion for the corresponding period in 2014. The decrease was primarily due to a 27.8% decrease in the average cost of natural gas per KWH generated, an 11.1% decrease in the average cost of coal per KWH generated, and a 10.6% decrease in the volume of KWHs generated by coal, partially offset by a 19.7% increase in the volume of KWHs generated by natural gas.

For year-to-date 2015, fuel expense was $2.4 billion compared to $3.1 billion for the corresponding period in 2014. The decrease was primarily due to a 31.8% decrease in the average cost of natural gas per KWH generated, a 21.2% decrease in the volume of KWHs generated by coal, and a 12.0% decrease in the average cost of coal per KWH generated, partially offset by a 32.3% increase in the volume of KWHs generated by natural gas.

Purchased Power

In the second quarter 2015, purchased power expense was $171 million compared to $133 million for the corresponding period in 2014. The increase was primarily due to a 50.0% increase in the volume of KWHs purchased primarily as a result of increased demand from warmer weather in the second quarter 2015 as compared to the corresponding period in 2014, partially offset by a 24.0% decrease in the average cost per KWH purchased.

For year-to-date 2015, purchased power expense was $315 million compared to $320 million for the corresponding period in 2014. The decrease was primarily due to a 23.7% decrease in the average cost per KWH purchased primarily as a result of lower natural gas prices, partially offset by an 18.0% increase in the volume of KWHs purchased.

Energy purchases will vary depending on demand for energy within the Southern Company system's 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.

Other Operations and Maintenance Expenses

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$81	7.9	$217	10.8

In the second quarter 2015, other operations and maintenance expenses were $1.1 billion compared to $1.0 billion for the corresponding period in 2014. The increase was primarily due to a $32 million increase in generation expenses primarily related to non-outage operations and maintenance, a $23 million increase in employee compensation and benefits including pension costs, and a $6 million increase in customer accounts, service, and sales costs primarily related to customer incentive and demand side management programs, partially offset by a $7 million decrease in transmission and distribution costs primarily related to overhead line maintenance. In addition, in the second quarter 2014, Alabama Power deferred approximately $16 million of certain non-nuclear outage expenditures under an accounting order.

For year-to-date 2015, other operations and maintenance expenses were $2.2 billion compared to $2.0 billion for the corresponding period in 2014. The increase was primarily due to a $58 million increase in employee compensation and benefits including pension costs, a $41 million increase in generation expenses primarily related to non-outage operations and maintenance, a $30 million increase in scheduled outage and maintenance costs at generation facilities, and a $22 million increase in customer accounts, service, and sales costs primarily related to customer incentive and demand side management programs. In addition, in the first half of 2014, Alabama Power deferred approximately $41 million of certain non-nuclear outage expenditures under an accounting order.

See Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Alabama Power – Non-Nuclear Outage Accounting Order" in Item 8 of the Form 10-K for additional information related to non-nuclear outage expenditures. Also see Note (F) to the Condensed Financial Statements herein for additional information related to pension costs.

Depreciation and Amortization

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(4)	(0.8)	$(14)	(1.4)

For year-to-date 2015, depreciation and amortization was $987 million compared to $1.0 billion for the corresponding period in 2014. The decrease was primarily due to a $49 million reduction in depreciation rates at Alabama Power, a $14 million reduction in depreciation at Gulf Power, as approved by the Florida PSC, and a $9 million reduction in other cost of removal at Georgia Power, partially offset by a $49 million increase as a result of additional plant in service at the traditional operating companies and Southern Power. See Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Gulf Power – Retail Base Rate Case" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under "Retail Regulatory Matters – Gulf Power – Retail Base Rate Case" herein for additional information.

Estimated Loss on Kemper IGCC

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$23	N/M	$(348)	(91.6)

N/M – Not meaningful

In the second quarter 2015, an estimated probable loss on the Kemper IGCC of $23 million was recorded at Southern Company. For year-to-date 2015 and 2014, estimated probable losses on the Kemper IGCC of $32 million and $380 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 (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). See FUTURE EARNINGS POTENTIAL – "Construction Program – Integrated Coal Gasification Combined Cycle" and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information.

Allowance for Equity Funds Used During Construction

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(23)	(37.1)	$(17)	(14.3)

In the second quarter 2015, AFUDC equity was $39 million compared to $62 million for the corresponding period in 2014. For year-to-date 2015, AFUDC equity was $102 million compared to $119 million for the corresponding period in 2014. The decreases were primarily due to Mississippi Power placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service in August 2014 and lower AFUDC equity at Georgia Power. Additionally, for year-to-date 2015, the decrease in AFUDC equity was partially offset by environmental and transmission projects at the traditional operating companies. See Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information regarding the Kemper IGCC.

Interest Expense, Net of Amounts Capitalized

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(30)	(14.3)	$(23)	(5.5)

In the second quarter 2015, interest expense, net of amounts capitalized was $180 million compared to $210 million in the corresponding period in 2014. For year-to-date 2015, interest expense, net of amounts capitalized was $393 million compared to $416 million in the corresponding period in 2014. The decreases were primarily due to a $41 million decrease related to the termination of the asset purchase agreement (APA) between Mississippi Power and SMEPA which required the return of SMEPA's deposits at a lower rate of interest than accrued, partially offset by an increase in outstanding long-term debt. Also contributing to the year-to-date decrease was an increase in capitalized interest primarily resulting from AFUDC debt and carrying costs related to the Kemper IGCC. See Note (E) to the Condensed Financial Statements herein for additional information. Also see Note (B) "Integrated Coal Gasification Combined Cycle – Termination of Proposed Sale of Undivided Interest to SMEPA" herein for additional information.

Income Taxes

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(19)	(5.9)	$79	15.9

In the second quarter 2015, income taxes were $302 million compared to $321 million for the corresponding period in 2014. The decrease is primarily due to state income tax benefits realized in 2015 and increased federal income tax benefits related to ITCs in 2015 at Southern Power, partially offset by a decrease in non-taxable AFUDC equity, higher pre-tax earnings, and beneficial changes that impacted 2014 state income taxes.

For year-to-date 2015, income taxes were $576 million compared to $497 million for the corresponding period in 2014. The increase primarily reflects a reduction in tax benefits related to the estimated probable losses on Mississippi Power's construction of the Kemper IGCC recorded in 2014, beneficial changes that impacted 2014 state income taxes, and a decrease in non-taxable AFUDC equity, partially offset by otherwise lower pre-tax earnings in 2015, state income tax benefits realized in 2015, and increased federal income tax benefits related to ITCs in 2015 at Southern Power.

See Note (G) to the Condensed Financial Statements herein for additional information.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Southern Company's future earnings potential. The level of Southern Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Southern Company system's primary business of selling electricity. These factors include the traditional operating companies' 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 the completion and subsequent operation of the Kemper IGCC and Plant Vogtle Units 3 and 4 as well as other ongoing construction projects. Other major factors include the profitability of the competitive wholesale business and successfully expanding investments in renewable energy projects. Future earnings for the electricity business in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, new energy contracts 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 service territory. In addition, the level of future earnings for the wholesale business also depends on numerous factors including creditworthiness of customers, total generating capacity available and related costs, future acquisitions and

construction of generating facilities, including the impact of ITCs, and the successful remarketing of capacity as current contracts expire. Changes in regional and global economic conditions may impact sales for the traditional operating companies and Southern Power as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Southern Company in Item 7 of the Form 10-K.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis or through market-based contracts. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company in Item 7 and Note 3 to the financial statements of Southern Company under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

New Source Review Actions

See Note 3 to the financial statements of Southern Company under "Environmental Matters – New Source Review Actions" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements herein for additional information.

On June 25, 2015, the U.S. Department of Justice filed a joint stipulation between Alabama Power, the EPA, and the U.S. Department of Justice proposing to modify the 2006 consent decree to resolve all remaining claims for relief alleged in the case. If approved by the U.S. District Court for the Northern District of Alabama, Alabama Power will, without admitting liability, operate subject to emission rates and a cap on certain units and requirements to use only natural gas at certain units, including a unit co-owned by Mississippi Power; retire certain units at Plants Gorgas and Barry; pay a $100,000 civil penalty; and invest $1.5 million in electric transportation infrastructure projects over three years.

The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations," – "Retail Regulatory Matters – Alabama Power – Environmental Accounting Order," and – "Retail Regulatory Matters – Georgia Power – Integrated Resource Plans" of Southern Company in Item 7 and Note 3 to the financial statements of Southern Company under "Other Matters – Sierra Club Settlement Agreement" in Item 8 of the Form 10-K for additional information on planned unit retirements and fuel conversions at Alabama Power, Georgia Power, and Mississippi Power.

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Southern Company in Item 7 of the Form 10-K for additional information regarding the EPA's proposed regulations governing emissions during startup, shutdown, or malfunction (SSM), the final MATS rule, and the Cross State Air Pollution Rule (CSAPR).

On June 12, 2015, the EPA published a final rule requiring affected states (including Alabama, Florida, Georgia, Mississippi, North Carolina, and Texas) to revise or remove state implementation plan (SIP) provisions regarding excess emissions that occur during periods of SSM by no later than November 22, 2016. The ultimate impact of the

final rule will depend on the outcome of any legal challenges and the development and approval of SIPs by the affected states and cannot be determined at this time.

On June 29, 2015, the U.S. Supreme Court issued a decision finding that the EPA had failed to properly consider costs in its decision to regulate hazardous air pollutant emissions from electric generating units under the MATS rule and remanded the case to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The MATS rule remains in effect while the U.S. Court of Appeals for the District of Columbia Circuit and the EPA respond to the decision. The ultimate impact of this decision cannot be determined at this time.

On July 28, 2015, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion invalidating certain emissions budgets under the CSAPR Phase II emissions trading program for a number of states, including Alabama, Florida, Georgia, North Carolina, and Texas. The court's decision leaves the emissions trading program in place and remands the rule to the EPA for further action consistent with the court's decision. The court rejected all other pending challenges to the rule. The ultimate impact of this decision will depend on additional rulemaking and cannot be determined at this time.

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Southern Company in Item 7 of the Form 10-K for additional information regarding the EPA's and the U.S. Army Corps of Engineers' proposed rule revising the definition of waters of the U.S. under the Clean Water Act (CWA).

On June 29, 2015, the EPA and the U.S. Army Corps of Engineers jointly published a final rule revising the regulatory definition of waters of the U.S. for all 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 becomes effective August 28, 2015. The ultimate impact of the final rule will depend on the outcome of any legal challenges and the EPA's and the U.S. Army Corps of Engineers' field-level implementation of the rule and cannot be determined at this time.

Coal Combustion Residuals

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Coal Combustion Residuals" of Southern Company in Item 7 of the Form 10-K for additional information regarding the EPA's regulation of CCR.

On April 17, 2015, the EPA published the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule) in the Federal Register, setting October 19, 2015 as the effective date of the CCR Rule. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the traditional operating companies' ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. Based on initial estimates, Southern Company recorded incremental asset retirement obligations (ARO) of approximately $700 million related to the CCR Rule in the second quarter 2015. As further analysis is performed, including evaluation of the expected timing and method of compliance and refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, the traditional operating companies expect to periodically update these estimates. See Note (A) to the Condensed Financial Statements herein for additional information regarding these AROs.

Global Climate Issues

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" of Southern Company in Item 7 of the Form 10-K for additional information regarding the EPA's proposed regulation of CO_2 from fossil-fuel-fired electric generating units.

On August 3, 2015, the EPA released pre-publication versions of two final rules that would limit CO_2 emissions from fossil fuel-fired electric generating units. One of the final rules contains specific emission standards governing CO_2 emissions from new, modified, and reconstructed units. The other final rule 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. At the same time, the EPA also proposed a federal plan and proposed model rule that states can adopt or that would be put in place if, in response to the final guidelines, a state either does not submit a state plan or its plan is not approved by the EPA. 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. 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 market-based contracts. 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 on numerous factors including the Southern Company system's ongoing review of the final rules; the outcome of any 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; the impact of future changes in generation and emissions related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

FERC Matters

The traditional 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 operating companies and Southern Power filed a triennial market power analysis on June 30, 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional operating companies' and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional operating companies and in some adjacent areas. To retain market-based rate authority, the FERC directed the traditional 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 operating companies and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

Retail Fuel Cost Recovery

The traditional 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 operating companies continuously monitor their under or over recovered fuel cost balances. Georgia Power expects to file its next fuel case in September 2015. The ultimate outcome of this matter cannot be determined at this time.

See Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Alabama Power – Rate ECR" and "Retail Regulatory Matters – Georgia Power – Fuel Cost Recovery" in Item 8 of the Form 10-K for additional information.

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 its Rate RSE, Rate CNP, rate energy cost recovery, and natural disaster reserve rate. In addition, the Alabama PSC issues accounting orders to address current events impacting Alabama Power. See Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Alabama Power" in Item 8 of the Form 10-K for additional information regarding Alabama Power's rate mechanisms and accounting orders. The recovery balance of each regulatory clause for Alabama Power is reported in Note (B) to the Condensed Financial Statements herein.

Rate CNP

See Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Alabama Power – Rate CNP" and "– Non-Environmental Federal Mandated Costs Accounting Order" in Item 8 of the Form 10-K for additional information regarding Alabama Power's development of a revised cost recovery mechanism and the normal purchases and normal sales (NPNS) exception for wind PPAs.

On March 3, 2015, the Alabama PSC approved a modification to Rate CNP Environmental to include compliance costs for both environmental and non-environmental mandates. The recoverable non-environmental compliance costs result from laws, regulations, and other mandates directed at the utility industry involving the security, reliability, safety, sustainability, or similar considerations impacting Alabama Power's facilities or operations. This modification to Rate CNP Environmental was effective March 20, 2015 with the revised rate now defined as Rate CNP Compliance. Alabama Power incurred $30 million of non-environmental compliance costs during the first six months of 2015 and will be limited to recovery of $50 million for the year. Customer rates will not be impacted before January 2016; therefore, the modification will increase the under recovered position for Rate CNP Compliance during 2015.

In April 2015, the Financial Accounting Standards Board (FASB) proposed new accounting guidance to allow the NPNS exception for physical forward transactions in nodal energy markets, consistent with the manner in which Alabama Power currently accounts for its two wind PPAs. On July 9, 2015, the FASB ratified the consensus reached by the Emerging Issues Task Force to allow the exception in such cases and voted to issue a final accounting standard.

Environmental Accounting Order

In April 2015, as part of its environmental compliance strategy, Alabama Power retired Plant Gorgas Units 6 and 7. These units represented 200 MWs of Alabama Power's approximately 12,200 MWs of generating capacity. 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. No later than April 2016, Alabama Power expects to cease using coal at Plant Greene County Units 1 and 2 (300 MWs) and begin operating those units solely on natural gas. Subject to the final approval of the New Source Review stipulation, Alabama Power will also retire Plant Barry Unit 3 (225 MWs) which is currently unavailable for generation. See Note (B) to the Condensed Financial Statements herein for additional information regarding the New Source Review actions.

In accordance with an 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 over the remaining useful lives, as established prior to the decision for retirement. As a result, these decisions will not have a significant impact on Southern Company's financial statements.

Renewable Energy

On June 25, 2015, Alabama Power filed a petition with the Alabama PSC for a Renewable Generation Certificate (RGC). The RGC would develop a process that allows Alabama Power to build its own renewable projects each less than 80 MWs or purchase power from other renewable-generated sources up to 500 MWs. The Alabama PSC is expected to rule on this matter in August 2015. The ultimate outcome of this matter cannot be determined at this time.

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 of Southern Company under "Retail Regulatory Matters – Georgia Power" in Item 8 of the Form 10-K for additional information.

Renewables Development

As part of the Georgia Power Advanced Solar Initiative program, Georgia Power executed ten PPAs that were approved by the Georgia PSC in 2014 and provide for the purchase of energy from 515 MWs of solar capacity. These PPAs are expected to commence in December 2015 and 2016 and have terms ranging from 20 to 30 years. As a result of certain acquisitions by Southern Power, Georgia Power expects that 249 MWs of the 515 MWs of contracted capacity will be purchased from solar facilities owned or under development by Southern Power.

On June 15, 2015, Georgia Power executed a PPA to purchase a total of 58 MWs of biomass capacity and energy from a 79-MW facility in Georgia that will begin in 2017 and end in 2047. This PPA was approved by the Georgia PSC on April 15, 2015. Georgia Power also entered into an energy-only PPA for the remaining 21 MWs from the same facility.

On July 21, 2015, the Georgia PSC approved Georgia Power's request to build, own, and operate a 46-MW solar generation facility at a U.S. Marine Corps base in Albany, Georgia by the end of 2016.

Integrated Resource Plan

To comply with the April 16, 2015 effective date of the MATS rule, Plant Branch Units 1, 3, and 4 (1,266 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) were retired on April 15, 2015. In addition, operations were discontinued at Plant Mitchell Unit 3 (155 MWs) and its decertification will be requested in connection with the triennial Integrated Resource Plan in 2016. The switch to natural gas as the primary fuel is complete at Plant Yates Units 7 and 6 and the units were returned to service on May 4, 2015 and June 27, 2015, respectively.

Gulf Power

Renewables

On April 16, 2015, the Florida PSC approved three energy purchase agreements totaling 120 MWs of utility-scale solar generation located at three military installations in northwest Florida. On May 5, 2015, the Florida PSC approved an energy purchase agreement for up to 178 MWs of wind generation in central Oklahoma. Purchases under these agreements will be for energy only and will be recovered through Gulf Power's fuel cost recovery mechanism.

Mississippi Power

2015 Rate Case

On May 15, 2015 and July 10, 2015, Mississippi Power filed alternative rate proposals related to recovery of Kemper IGCC-related costs with the Mississippi PSC. See Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2015 Rate Case" herein for additional information.

Renewables

In April and May 2015, Mississippi Power entered into separate PPAs for three solar facilities for a combined total of approximately 105 MWs. Mississippi Power would purchase all of the energy produced by the solar facilities for the 25-year term of the contracts. If approved by the Mississippi PSC, the projects are expected to be in service by the end of 2016 and the resulting energy purchases will be recovered through Mississippi Power's fuel cost recovery mechanism. The ultimate outcome of this matter cannot be determined at this time.

Construction Program

Overview

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. The Southern Company system intends to continue its strategy of developing and constructing new generating facilities, as well as adding or changing fuel sources for certain existing units, adding environmental control equipment, and expanding the transmission and distribution systems. For the traditional 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.

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 582-MW Kemper IGCC. See Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" herein for additional information. For additional information about costs relating to Southern Power's acquisitions that involve construction of renewable energy facilities, see Note (I) to the Condensed Financial Statements herein.

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

Integrated Coal Gasification Combined Cycle

From 2013 through June 30, 2015, Southern Company recorded pre-tax charges totaling $2.08 billion ($1.28 billion after tax) for revisions of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC above the $2.88 billion cost cap established by the Mississippi PSC, net of the DOE Grants and excluding the Cost Cap Exceptions. In subsequent periods, any further changes in the estimated costs to complete construction of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in Southern Company's statements of income and these changes could be material.

On February 12, 2015, the Mississippi Supreme Court issued its decision in a legal challenge with respect to the Mississippi PSC's March 2013 order that authorized Mississippi Power's collection of $156 million annually to be recorded as Mirror CWIP. Among other things, the Mississippi Supreme Court reversed this order and directed the Mississippi PSC to enter an order requiring Mississippi Power to refund the Mirror CWIP amounts collected. As of June 30, 2015, $331 million had been collected by Mississippi Power. The Mississippi PSC ordered that the Mirror CWIP rate be terminated effective July 20, 2015.

On May 20, 2015, SMEPA notified Mississippi Power of its termination of the APA. Mississippi Power previously received a total of $275 million of deposits from SMEPA that were required to be returned to SMEPA with interest in connection with the termination of the APA. On June 3, 2015, Southern Company, pursuant to its guarantee obligation, returned approximately $301 million to SMEPA. Subsequently, Mississippi Power issued an 18-month promissory note in the aggregate principal amount of approximately $301 million to Southern Company.

The return of approximately $301 million to SMEPA in June 2015 in connection with the termination of the APA, the required refund of the approximately $353 million of Mirror CWIP rate collections, including associated carrying costs, and the termination of the Mirror CWIP rates have adversely impacted Mississippi Power's ability to obtain financing needed for its business operations. As a result, on July 10, 2015, Mississippi Power submitted a request for interim rates 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. These interim rates are designed to collect approximately $159 million annually. Evidentiary hearings on the interim rate relief are scheduled to be held on August 6, 2015. The ultimate outcome of these matters cannot be determined at this time.

Nuclear Construction

On January 29, 2015, Georgia Power announced it was notified by the Contractor of the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4, which would incrementally delay the previously disclosed estimated in-service dates by 18 months (from the fourth quarter of 2017 to the second quarter of 2019 for Unit 3 and from the fourth quarter of 2018 to the second quarter of 2020 for Unit 4).

While Georgia Power has not agreed to any change to the guaranteed substantial completion dates (April 2016 for Unit 3 and April 2017 for Unit 4) included in the engineering, procurement, and construction agreement relating to Plant Vogtle Units 3 and 4, Georgia Power's twelfth Vogtle Construction Monitoring (VCM) report, filed February 27, 2015, included a requested amendment (Requested Amendment) to the Plant Vogtle Units 3 and 4 certificate to reflect the Contractor's revised forecast, to include the estimated owner's costs associated with the proposed 18-month Contractor delay, and to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 from $4.4 billion to $5.0 billion. No Contractor costs related to the Contractor's proposed 18-month delay were included in the twelfth VCM report. The twelfth VCM report estimated financing costs during the construction period to total approximately $2.5 billion.

On April 15, 2015, the Georgia PSC issued a procedural order in connection with the twelfth VCM report. Pursuant to this order, the Georgia PSC deemed the Requested Amendment unnecessary and withdrawn until the completion of construction of Plant Vogtle Unit 3. The Georgia PSC recognized that the certified cost does not constitute a cost recovery cap. In accordance with the Georgia Integrated Resource Planning Act, any costs incurred by Georgia Power in excess of the certified amount will be included in rate base, provided Georgia Power shows the costs to be reasonable and prudent. Financing costs up to the certified amount will be collected through the NCCR tariff until the units are placed in service, while financing costs on any construction-related costs in excess of the $4.4 billion certified amount are expected to be recovered through AFUDC.

Additionally, there are certain risks associated with the construction program in general and certain risks associated with the licensing, construction, and operation of nuclear generating units in particular, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. The ultimate outcome of these events cannot be determined at this time.

Income Tax Matters

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Income Tax Matters" of Southern Company in Item 7 of the Form 10-K for additional information.

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 for 2013 and 2014. In May 2015, Southern Company amended its 2008 through 2013 federal income tax returns to include deductions for Kemper IGCC-related R&E expenditures. Due to the uncertainty related to this tax position, Southern Company had unrecognized tax benefits associated with these R&E deductions totaling approximately $390 million as of June 30, 2015. See Note 5 to the financial statements of Southern Company under "Unrecognized Tax Benefits" in Item 8 of the Form 10-K and Notes (B) and (G) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" and "Unrecognized Tax

Benefits – Section 174 Research and Experimental Deduction," respectively, herein for additional information. The ultimate outcome of this tax matter cannot be determined at this time.

Other Matters

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

The ultimate outcome of such pending or potential litigation against Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported in Note (B) to the Condensed Financial Statements herein or in Note 3 to the financial statements of Southern Company in Item 8 of the Form 10-K, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Company's financial statements. See Note (B) to the Condensed Financial Statements herein for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Southern Company prepares its consolidated financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Southern Company in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Southern Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Southern Company in Item 7 of the Form 10-K for a complete discussion of Southern Company's critical accounting policies and estimates related to Electric Utility Regulation, Contingent Obligations, and Pension and Other Postretirement Benefits.

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

During 2015, 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 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 DOE Grants and excluding the Cost Cap Exceptions.

As a result of the revisions to the cost estimate, Southern Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC of $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 $2.08 billion ($1.28 billion after tax) as a result of changes in the cost estimate for the Kemper IGCC through June 30, 2015.

Mississippi Power has experienced, and may continue to experience, material changes in the cost estimate for the Kemper IGCC. In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the 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 further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (including major equipment failure and system integration), and/or operational performance (including, but not limited to, additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC).

Mississippi Power's revised cost estimate includes costs through March 31, 2016. Any further extension of the in-service date is currently estimated to result in additional base costs of approximately $25 million to $30 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. Any further extension of the in-service date with respect to the Kemper IGCC 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 $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting fees and legal fees which are being deferred as regulatory assets and are estimated to total approximately $7 million per month.

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 of Southern Company under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information.

Asset Retirement Obligations

AROs are computed as the fair value of the 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 nuclear facilities - Alabama Power's Plant Farley and Georgia Power's ownership interests in Plants Hatch and Vogtle - and facilities that are subject to the CCR Rule, primarily ash ponds. In addition, the Southern Company system has retirement obligations related to various landfill sites, asbestos removal, mine reclamation, and disposal of polychlorinated biphenyls in certain transformers. The Southern Company system also has identified retirement obligations related to certain 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 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.

On April 17, 2015, the EPA published the final CCR Rule in the Federal Register, setting October 19, 2015 as the effective date of the CCR Rule. Therefore, Alabama Power, Gulf Power, and Mississippi Power recorded new AROs for facilities that are subject to the CCR Rule. Georgia Power had previously recorded AROs as a result of state requirements in Georgia which closely align with the requirements of the CCR Rule. The cost estimates are based

on information that was known as of June 30, 2015 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. As further analysis is performed, including evaluation of the expected timing and method of compliance and refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, the traditional operating companies expect to periodically update these estimates. 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 of Southern Company under "Asset Retirement Obligations and Other Costs of Removal" and "Nuclear Decommissioning" in Item 8 of the Form 10-K and Note (A) to the Condensed Financial Statements under "Asset Retirement Obligations" herein for additional information.

Recently Issued Accounting Standards

The FASB's ASC 606, *Revenue from Contracts with Customers*, revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. Southern Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*. The ASU requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. Southern Company currently reflects unamortized debt issuance costs in unamortized debt issuance expense on its balance sheet. Upon adoption, the reclassification will not have a material impact on the results of operations, financial position, or cash flows of Southern Company.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Overview" of Southern Company in Item 7 of the Form 10-K for additional information. Southern Company's financial condition remained stable at June 30, 2015. Through June 30, 2015, Southern Company has incurred non-recoverable cash expenditures of $1.62 billion and is expected to incur approximately $0.46 billion in additional non-recoverable cash expenditures through completion of the Kemper IGCC. Southern Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit agreements to meet future capital and liquidity needs. See "Capital Requirements and Contractual Obligations," "Sources of Capital," and "Financing Activities" herein for additional information.

Net cash provided from operating activities totaled $2.1 billion for the first six months of 2015, an increase of $37 million from the corresponding period in 2014. The increase in net cash provided from operating activities was primarily due to an increase in fuel cost recovery, partially offset by timing of accounts payable. Net cash used for investing activities totaled $2.8 billion for the first six months of 2015 primarily due to gross property additions for installation of equipment to comply with environmental standards, construction of generation, transmission, and distribution facilities, and acquisitions of solar facilities. Net cash provided from financing activities totaled $762 million for the first six months of 2015. This was primarily due to issuances of long-term debt, partially offset by common stock dividend payments and redemptions of long-term debt and preferred and preference stock. Fluctuations in cash flow from financing activities vary from period to period based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for the first six months of 2015 include an increase of $2.1 billion in total property, plant, and equipment to comply with environmental standards and construction of generation, transmission, and distribution facilities, a $444 million increase in income taxes receivable, non-current associated with federal income tax benefits for deductions primarily related to R&E expenditures for the Kemper IGCC, and an increase of $406 million in accounts receivable primarily related to increases in customer billings as compared to

December 31, 2014. Other significant changes include a $2.1 billion increase in short-term and long-term debt to fund the Southern Company subsidiaries' continuous construction programs and for other general corporate purposes, a $692 million increase in AROs primarily related to the CCR Rule, and a $619 million increase in accumulated deferred income taxes for deductions primarily related to R&E expenditures for the Kemper IGCC. See Notes (A), (B), and (G) to the Condensed Financial Statements herein for additional information regarding AROs, the Kemper IGCC, and R&E expenditures, respectively.

At the end of the second quarter 2015, the market price of Southern Company's common stock was $41.90 per share (based on the closing price as reported on the New York Stock Exchange) and the book value was $22.22 per share, representing a market-to-book ratio of 189%, compared to $49.11, $21.98, and 223%, respectively, at the end of 2014. Southern Company's common stock dividend for the second quarter 2015 was $0.5425 per share compared to $0.5250 per share in the second quarter 2014.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company in Item 7 of the Form 10-K for a description of Southern Company's capital requirements for the construction programs of the Southern Company system, including estimated capital expenditures for new generating facilities and to comply with existing environmental statutes and regulations, scheduled maturities of long-term debt, as well as related interest, derivative obligations, preferred and preference stock dividends, leases, purchase commitments, trust funding requirements, and unrecognized tax benefits. Approximately $3.7 billion will be required through June 30, 2016 to fund maturities and announced redemptions of long-term debt. See "Sources of Capital" herein for additional information.

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in 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; 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. Additionally, planned expenditures for plant acquisitions may vary materially due to market opportunities and Southern Power's ability to execute its growth strategy. See Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" herein for information regarding additional factors that may impact construction expenditures.

Sources of Capital

Southern Company intends to meet its future capital needs through operating cash flows, short-term debt, term loans, and external security issuances. Equity capital can be provided from any combination of Southern Company's stock plans, private placements, or public offerings. The amount and timing of additional equity capital and debt to be raised in 2015, as well as in subsequent years, will be contingent on Southern Company's investment opportunities and the Southern Company system's capital requirements.

Except as described herein, the traditional operating companies and Southern Power plan to obtain the funds required for construction and other purposes from operating cash flows, external security issuances, term loans, short-term borrowings, and equity contributions or loans from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Southern Company in Item 7 of the Form 10-K for additional information.

In addition, Georgia Power 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 Eligible Project Costs incurred in connection with its construction of Plant Vogtle Units 3 and 4. Under the Loan Guarantee Agreement, the DOE agreed to guarantee borrowings of up to $3.46 billion (not to exceed 70% of Eligible Project Costs) to be made by Georgia Power under a multi-advance credit facility (FFB Credit Facility) among Georgia Power, the DOE, and the FFB. Eligible Project Costs incurred through June 30, 2015 would allow for borrowings of up to $2.2 billion under the FFB Credit Facility, of which Georgia Power has borrowed $1.8 billion. See Note 6 to the financial statements of Southern Company under "DOE Loan Guarantee Borrowings" in Item 8 of the Form 10-K for additional information regarding the Loan Guarantee Agreement and Note (B) to the Condensed Financial Statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" herein for additional information regarding Plant Vogtle Units 3 and 4.

Mississippi Power received $245 million of DOE Grants in prior years that were used for the construction of the Kemper IGCC. An additional $25 million of DOE Grants is expected to be received for commercial operation of the Kemper IGCC. In addition, see Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for information regarding legislation related to the securitization of certain costs of the Kemper IGCC.

As of June 30, 2015, Southern Company's current liabilities exceeded current assets by $2.1 billion, primarily due to long-term debt that is due within one year of $3.6 billion, including approximately $0.4 billion at Southern Company, $0.6 billion at Alabama Power, $1.7 billion at Georgia Power, $0.4 billion at Mississippi Power, and $0.5 billion at Southern Power. In addition, Mississippi Power has $0.5 billion in short-term bank loans scheduled to mature on April 1, 2016. To meet short-term cash needs and contingencies, Southern Company has substantial cash flow from operating activities and access to capital markets and financial institutions. Southern Company, the traditional operating companies, and Southern Power 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 operating companies and Southern Power, equity contributions and/or loans from Southern Company to meet their short-term capital needs. In addition, for the remainder of 2015, Georgia Power expects to utilize borrowings through the FFB Credit Facility as its primary source of long-term borrowed funds.

The financial condition of Mississippi Power was adversely affected by the return of approximately $301 million of interest bearing refundable deposits to SMEPA in June 2015. In addition, the required refund of Mirror CWIP rate collections of approximately $353 million as of June 30, 2015, including associated carrying costs, and the termination of the Mirror CWIP rate have further adversely impacted Mississippi Power's financial condition and its ability to obtain funds needed for normal business operations and completion of the Kemper IGCC. Mississippi Power plans to obtain the funds required for construction and other purposes from operating cash flows and lines of credit (to the extent available) as well as loans and, under certain circumstances, equity contributions from Southern Company. See Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information.

At June 30, 2015, Southern Company and its subsidiaries had approximately $0.8 billion of cash and cash equivalents. Committed credit arrangements with banks at June 30, 2015 were as follows:

	Expires						Executable Term Loans		Due Within One Year	
Company	2015	2016	2017	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
	(in millions)				(in millions)		(in millions)		(in millions)	
Southern Company	$ —	$ —	$ —	$ 1,000	$ 1,000	$ 1,000	$ —	$ —	$ —	$ —
Alabama Power	154	124	—	1,030	1,308	1,307	58	—	58	170
Georgia Power	—	150	—	1,600	1,750	1,737	—	—	—	150
Gulf Power	20	225	30	—	275	275	50	—	50	195
Mississippi Power	40	255	—	—	295	265	30	40	70	225
Southern Power	—	—	—	500	500	466	—	—	—	—
Other	25	45	—	—	70	70	20	—	20	50
Total	$ 239	$ 799	$ 30	$ 4,130	$ 5,198	$ 5,120	$ 158	$ 40	$ 198	$ 790

See Note 6 to the financial statements of Southern Company under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information.

A portion of the unused credit with banks is allocated to provide liquidity support to the traditional operating companies' variable rate pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of June 30, 2015 was approximately $1.9 billion. In addition, at June 30, 2015, the traditional operating companies had $368 million of fixed rate pollution control revenue bonds outstanding that were required to be reoffered within the next 12 months.

Most of these bank credit arrangements contain covenants that limit debt levels and contain 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. Southern Company, the traditional operating companies, and Southern Power are currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

Subject to applicable market conditions, 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, the traditional operating companies, and Southern Power make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. Southern Company, the traditional operating companies, and Southern Power may also borrow through various other arrangements with banks. 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 June 30, 2015		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)*
Commercial paper	$ 512	0.3%	$ 1,155	0.3%	$ 1,563
Short-term bank debt	545	1.3%	717	1.2%	795
Total	$ 1,057	0.7%	$ 1,872	0.7%	

(*) Average and maximum amounts are based upon daily balances during the three-month period ended June 30, 2015.

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

Credit Rating Risk

Southern Company and its subsidiaries do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change of certain subsidiaries to BBB and Baa2, or 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, interest rate derivatives, and construction of new generation at Plant Vogtle Units 3 and 4.

The maximum potential collateral requirements under these contracts at June 30, 2015 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and Baa2	$ 9
At BBB- and/or Baa3	488
Below BBB- and/or Baa3	2,407

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the ability of Southern Company and its subsidiaries to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

On June 5, 2015, Fitch downgraded the long-term issuer default rating of Mississippi Power to BBB+ from A-. Fitch maintained the negative ratings outlook for Mississippi Power and revised the ratings outlook for Southern Company from stable to negative.

Subsequent to June 30, 2015, S&P placed its ratings of Southern Company and the traditional operating companies on CreditWatch with negative implications.

Financing Activities

During the first six months of 2015, Southern Company issued approximately 3.2 million shares of common stock primarily through the employee equity compensation plan and received proceeds of approximately $116 million. Southern Company is not currently issuing shares of common stock through the Southern Investment Plan or its employee savings plan. All sales under the Southern Investment Plan and the employee savings plan are currently being funded with shares acquired on the open market by independent plan administrators.

On March 2, 2015, Southern Company announced a program to repurchase up to 20 million shares of Southern Company common stock to offset all or a portion of the incremental shares issued under its employee and director equity compensation plans, including through stock option exercises, until December 31, 2017. Under this program, approximately 2.6 million shares have been repurchased through June 30, 2015 at a total cost of approximately $115 million. Pursuant to board approval, Southern Company may repurchase shares through open market purchases or privately negotiated transactions, including accelerated or other share repurchase programs, in accordance with applicable securities laws.

The following table outlines the long-term debt financing activities for Southern Company and its subsidiaries for the first six months of 2015:

Company[a]	Senior Note Issuances	Senior Note Redemptions	Revenue Bond Issuances and Reofferings of Purchased Bonds[b]	Revenue Bond Maturities and Repurchases	Other Long-Term Debt Issuances	Other Long-Term Debt Redemptions and Maturities[c]
			(in millions)			
Southern Company	$ 600	$ —	$ —	$ —	$ —	$ —
Alabama Power	975	250	80	134	—	—
Georgia Power	—	125	170	65	600	5
Mississippi Power	—	—	—	—	—	351
Southern Power	650	—	—	—	—	—
Other	—	—	—	—	—	9
Total	$ 2,225	$ 375	$ 250	$ 199	$ 600	$ 365

(a) Gulf Power did not issue or redeem any long-term debt during the first six months of 2015.

(b) Includes reoffering by Alabama Power of $80 million aggregate principal amount of revenue bonds previously purchased and held by Alabama Power since April 2015 and reofferings by Georgia Power of $104.6 million and $65 million aggregate principal amount of revenue bonds previously purchased and held by Georgia Power since 2013 and April 2015, respectively.

(c) Includes reductions in capital lease obligations resulting from cash payments under capital leases.

In June 2015, Southern Company issued $600 million aggregate principal amount of Series 2015A 2.750% Senior Notes due June 15, 2020. The proceeds were used to pay a portion of Southern Company's outstanding short-term indebtedness and for other general corporate purposes.

Southern Company's subsidiaries used the proceeds of the debt issuance 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.

Alabama Power's "Senior Note Issuances" reflected in the table above includes issuances in April 2015 of $175 million additional aggregate principal amount of its Series 2015A 3.750% Senior Notes due March 1, 2045 (Additional Series 2015A Senior Notes) and $250 million aggregate principal amount of its Series 2015B 2.800% Senior Notes due April 1, 2025 (Series 2015B Senior Notes). A portion of the proceeds of the Additional Series 2015A Senior Notes and the Series 2015B Senior Notes were used to redeem in May 2015 6.48 million shares ($162 million aggregate stated capital) of Alabama Power's 5.20% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date, 4.0 million shares ($100 million aggregate stated capital) of Alabama Power's 5.30% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date, and 6.0 million shares ($150 million aggregate stated capital) of Alabama Power's 5.625% Series Preference Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date, and the remaining net proceeds were used for general corporate purposes, including Alabama Power's continuous construction program.

Georgia Power's "Other Long-Term Debt Issuances" reflected in the table above include borrowings under the FFB Credit Facility in an aggregate principal amount of $600 million in June 2015. The interest rate applicable to the $600 million principal amount is 3.283% for an interest period that extends 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. Georgia Power settled $350 million of interest rate swaps related to this borrowing for approximately $6 million, which will be amortized to interest expense over 10 years.

In March 2015, Georgia Power entered into a $250 million aggregate principal amount three-month floating rate bank loan bearing interest based on one-month LIBOR. The proceeds were used for working capital and other general corporate purposes and the loan was repaid at maturity.

In April 2015, Mississippi Power entered into two floating rate bank loans with a maturity date of April 1, 2016, in an aggregate principal amount of $475 million, bearing interest based on one-month LIBOR. The proceeds of these loans were used for the repayment of term loans in an aggregate principal amount of $275 million, working capital, and other general corporate purposes, including Mississippi Power's ongoing construction program. Mississippi Power also amended three outstanding floating rate bank loans for an aggregate principal amount of $425 million which, among other things, extended the maturity dates from various dates in 2015 to April 1, 2016.

In June 2015, Gulf Power entered into a three-month floating rate bank loan bearing interest based on one-month LIBOR. This short-term loan was for $40 million aggregate principal amount and the proceeds were used for credit support, working capital, and other general corporate purposes.

In addition to the amounts reflected in the table above, Mississippi Power previously received a total of $275 million of deposits from SMEPA that were required to be returned to SMEPA with interest in connection with the termination of the APA. On June 3, 2015, Southern Company, pursuant to its guarantee obligation, returned approximately $301 million to SMEPA. Subsequently, Mississippi Power issued an 18-month floating rate promissory note to Southern Company in an aggregate principal amount of approximately $301 million bearing interest based on one-month LIBOR. See Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle – Termination of Proposed Sale of Undivided Interest to SMEPA" herein for additional information.

Subsequent to June 30, 2015, Southern Power Company repaid at maturity $525 million aggregate principal amount of its 4.875% Senior Notes on July 15, 2015.

Also subsequent to June 30, 2015, $97.925 million aggregate principal amount of the Development Authority of Putnam County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Branch Project), First Series 1996, First Series 1997, Second Series 1997, and First Series 1998 were redeemed.

Also subsequent to June 30, 2015, Gulf Power announced the redemption in September 2015 of $60 million aggregate principal amount of its Series L 5.65% Senior Notes due September 1, 2035.

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

PART I

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

During the six months ended June 30, 2015, there were no material changes to each registrant's disclosures about market risk. For an in-depth discussion of each registrant's market risks, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of each registrant in Item 7 of the Form 10-K and Note 1 to the financial statements of each registrant under "Financial Instruments," Note 11 to the financial statements of Southern Company, Alabama Power, and Georgia Power, Note 10 to the financial statements of Gulf Power and Mississippi Power, and Note 9 to the financial statements of Southern Power in Item 8 of the Form 10-K. Also, see Note (H) to the Condensed Financial Statements herein for information relating to derivative instruments.

Item 4. Controls and Procedures.

(a) Evaluation of disclosure controls and procedures.

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

(b) Changes in internal controls.

There have been no changes in Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, or Southern Power Company's 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) during the second quarter 2015 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, or Southern Power Company's internal control over financial reporting.

[This page intentionally left blank]

ALABAMA POWER COMPANY

ALABAMA POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	**2015**	2014
	(in millions)		*(in millions)*	
Operating Revenues:				
Retail revenues	**$ 1,326**	$ 1,249	**$ 2,594**	$ 2,546
Wholesale revenues, non-affiliates	**57**	65	**123**	150
Wholesale revenues, affiliates	**20**	68	**35**	137
Other revenues	**52**	55	**104**	112
Total operating revenues	**1,455**	1,437	**2,856**	2,945
Operating Expenses:				
Fuel	**343**	414	**653**	846
Purchased power, non-affiliates	**45**	39	**86**	96
Purchased power, affiliates	**49**	37	**103**	86
Other operations and maintenance	**370**	330	**768**	655
Depreciation and amortization	**160**	172	**318**	347
Taxes other than income taxes	**90**	88	**184**	177
Total operating expenses	**1,057**	1,080	**2,112**	2,207
Operating Income	**398**	357	**744**	738
Other Income and (Expense):				
Allowance for equity funds used during construction	**14**	11	**29**	21
Interest expense, net of amounts capitalized	**(69)**	(63)	**(134)**	(125)
Other income (expense), net	**(14)**	(3)	**(18)**	(8)
Total other income and (expense)	**(69)**	(55)	**(123)**	(112)
Earnings Before Income Taxes	**329**	302	**621**	626
Income taxes	**122**	119	**235**	246
Net Income	**207**	183	**386**	380
Dividends on Preferred and Preference Stock	**7**	10	**17**	20
Net Income After Dividends on Preferred and Preference Stock	**$ 200**	$ 173	**$ 369**	$ 360

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	**2015**	2014
	(in millions)		*(in millions)*	
Net Income	**$ 207**	$ 183	**$ 386**	$ 380
Other comprehensive income (loss):				
Qualifying hedges:				
Changes in fair value, net of tax of $3, $-, $- and $-, respectively	**5**	—	**1**	—
Reclassification adjustment for amounts included in net income, net of tax of $-, $-, $1, and $-, respectively	**—**	—	**1**	1
Total other comprehensive income (loss)	**5**	—	**2**	1
Comprehensive Income	**$ 212**	$ 183	**$ 388**	$ 381

The accompanying notes as they relate to Alabama Power are an integral part of these condensed financial statements.

ALABAMA POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Six Months Ended June 30,	
	2015	2014
	(in millions)	
Operating Activities:		
Net income	**$ 386**	$ 380
Adjustments to reconcile net income to net cash provided from operating activities —		
Depreciation and amortization, total	**387**	416
Deferred income taxes	**60**	49
Allowance for equity funds used during construction	**(29)**	(21)
Other, net	**(23)**	(40)
Changes in certain current assets and liabilities —		
-Receivables	**(115)**	(120)
-Fossil fuel stock	**19**	94
-Materials and supplies	**3**	(2)
-Other current assets	**(55)**	(57)
-Accounts payable	**(212)**	(94)
-Accrued taxes	**177**	104
-Accrued compensation	**(66)**	(17)
-Retail fuel cost over recovery	**25**	(23)
-Other current liabilities	**40**	5
Net cash provided from operating activities	**597**	674
Investing Activities:		
Property additions	**(612)**	(637)
Nuclear decommissioning trust fund purchases	**(278)**	(121)
Nuclear decommissioning trust fund sales	**278**	121
Cost of removal, net of salvage	**(28)**	(30)
Change in construction payables	**28**	71
Other investing activities	**(14)**	(13)
Net cash used for investing activities	**(626)**	(609)
Financing Activities:		
Increase in notes payable, net	**—**	27
Proceeds —		
Senior notes issuances	**975**	—
Capital contributions from parent company	**10**	12
Pollution control revenue bonds	**80**	—
Redemptions and repurchases —		
Preferred and preference stock	**(412)**	—
Pollution control revenue bonds	**(134)**	—
Senior notes	**(250)**	—
Payment of preferred and preference stock dividends	**(22)**	(20)
Payment of common stock dividends	**(286)**	(275)
Other financing activities	**(10)**	1
Net cash used for financing activities	**(49)**	(255)
Net Change in Cash and Cash Equivalents	**(78)**	(190)
Cash and Cash Equivalents at Beginning of Period	**273**	295
Cash and Cash Equivalents at End of Period	**$ 195**	$ 105
Supplemental Cash Flow Information:		
Cash paid during the period for —		
Interest (net of $10 and $8 capitalized for 2015 and 2014, respectively)	**$ 118**	$ 114
Income taxes, net	**47**	141
Noncash transactions — Accrued property additions at end of period	**35**	89

The accompanying notes as they relate to Alabama Power are an integral part of these condensed financial statements.

ALABAMA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Assets	At June 30, 2015	At December 31, 2014
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 195**	$ 273
Receivables —		
Customer accounts receivable	**393**	345
Unbilled revenues	**170**	138
Under recovered regulatory clause revenues	**28**	74
Other accounts and notes receivable	**31**	23
Affiliated companies	**41**	37
Accumulated provision for uncollectible accounts	**(9)**	(9)
Fossil fuel stock, at average cost	**249**	268
Materials and supplies, at average cost	**415**	406
Vacation pay	**65**	65
Prepaid expenses	**168**	244
Other regulatory assets, current	**115**	84
Other current assets	**10**	5
Total current assets	**1,871**	1,953
Property, Plant, and Equipment:		
In service	**23,812**	23,080
Less accumulated provision for depreciation	**8,565**	8,522
Plant in service, net of depreciation	**15,247**	14,558
Nuclear fuel, at amortized cost	**338**	348
Construction work in progress	**1,017**	1,006
Total property, plant, and equipment	**16,602**	15,912
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**68**	66
Nuclear decommissioning trusts, at fair value	**758**	756
Miscellaneous property and investments	**88**	84
Total other property and investments	**914**	906
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**526**	525
Deferred under recovered regulatory clause revenues	**97**	31
Other regulatory assets, deferred	**1,054**	1,063
Other deferred charges and assets	**156**	162
Total deferred charges and other assets	**1,833**	1,781
Total Assets	**$ 21,220**	$ 20,552

The accompanying notes as they relate to Alabama Power are an integral part of these condensed financial statements.

ALABAMA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	**At June 30, 2015**	At December 31, 2014
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 600**	$ 454
Accounts payable —		
Affiliated	**244**	248
Other	**267**	443
Customer deposits	**88**	87
Accrued taxes —		
Accrued income taxes	**3**	2
Other accrued taxes	**88**	37
Accrued interest	**75**	66
Accrued vacation pay	**54**	54
Accrued compensation	**66**	131
Other current liabilities	**105**	82
Total current liabilities	**1,590**	1,604
Long-term Debt	**6,699**	6,176
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**3,937**	3,874
Deferred credits related to income taxes	**71**	72
Accumulated deferred investment tax credits	**121**	125
Employee benefit obligations	**308**	326
Asset retirement obligations	**1,252**	829
Other cost of removal obligations	**742**	744
Other regulatory liabilities, deferred	**219**	239
Deferred over recovered regulatory clause revenues	**72**	47
Other deferred credits and liabilities	**79**	79
Total deferred credits and other liabilities	**6,801**	6,335
Total Liabilities	**15,090**	14,115
Redeemable Preferred Stock	**85**	342
Preference Stock	**196**	343
Common Stockholder's Equity:		
Common stock, par value $40 per share —		
Authorized — 40,000,000 shares		
Outstanding — 30,537,500 shares	**1,222**	1,222
Paid-in capital	**2,324**	2,304
Retained earnings	**2,331**	2,255
Accumulated other comprehensive loss	**(28)**	(29)
Total common stockholder's equity	**5,849**	5,752
Total Liabilities and Stockholder's Equity	**$ 21,220**	$ 20,552

The accompanying notes as they relate to Alabama Power are an integral part of these condensed financial statements.

OVERVIEW

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

Many factors affect the opportunities, challenges, and risks of Alabama Power's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, fuel, capital expenditures, and restoration following major storms. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge Alabama Power for the foreseeable future.

Alabama Power continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Key Performance Indicators" of Alabama Power in Item 7 of the Form 10-K.

RESULTS OF OPERATIONS

Net Income

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$27	15.6	$9	2.5

Alabama Power's net income after dividends on preferred and preference stock for the second quarter 2015 was $200 million compared to $173 million for the corresponding period in 2014. The increase was primarily related to an increase in rates under rate stabilization and equalization (Rate RSE) effective January 1, 2015, warmer weather in the second quarter 2015 compared to the corresponding period in 2014, and a decrease in depreciation, partially offset by an increase in non-fuel operations and maintenance expenses. Alabama Power's net income after dividends on preferred and preference stock for year-to-date 2015 was $369 million compared to $360 million for the corresponding period in 2014. The increase was primarily related to an increase under Rate RSE and a decrease in depreciation, partially offset by an increase in non-fuel operations and maintenance expenses.

Retail Revenues

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$77	6.2	$48	1.9

In the second quarter 2015, retail revenues were $1.33 billion compared to $1.25 billion for the corresponding period in 2014. For year-to-date 2015, retail revenues were $2.59 billion compared to $2.55 billion for the corresponding period in 2014.

Details of the changes in retail revenues were as follows:

	Second Quarter 2015		Year-to-Date 2015	
	(in millions)	*(% change)*	*(in millions)*	*(% change)*
Retail – prior year	$ 1,249		$ 2,546	
Estimated change resulting from –				
Rates and pricing	56	4.5	103	4.1
Sales growth	1	0.1	10	0.4
Weather	18	1.5	(2)	(0.1)
Fuel and other cost recovery	2	0.1	(63)	(2.5)
Retail – current year	$ 1,326	6.2%	$ 2,594	1.9%

Revenues associated with changes in rates and pricing increased in the second quarter 2015 and year-to-date 2015 when compared to the corresponding periods in 2014 primarily due to a Rate RSE increase effective January 1, 2015. See Note 3 to the financial statements of Alabama Power under "Retail Regulatory Matters" in Item 8 of the Form 10-K for additional information.

Revenues attributable to changes in sales remained relatively flat in the second quarter 2015 and increased slightly year-to-date 2015 when compared to the corresponding periods in 2014. Industrial KWH energy sales slightly increased 0.2% year-to-date 2015 as a result of an increase in demand resulting from changes in production levels primarily in the pipelines, stone, clay, and glass, automotive, and plastics sectors, offset by a decrease in demand in the primary metals and forest products sectors. Weather-adjusted residential and commercial KWH energy sales were relatively flat for year-to-date 2015.

Revenues resulting from changes in weather increased in the second quarter 2015 due to warmer weather experienced in Alabama Power's service territory in the second quarter 2015 as compared to the corresponding period in 2014. For the second quarter 2015, the resulting increases were 2.6% and 1.5% for residential and commercial sales revenues, respectively.

Revenues resulting from changes in weather remained relatively flat year-to-date 2015 primarily due to milder weather experienced in Alabama Power's service territory in the first quarter 2015 offset by warmer weather in the second quarter 2015 as compared to the corresponding periods in 2014.

Fuel and other cost recovery revenues increased in the second quarter 2015 when compared to the corresponding period in 2014 primarily due to an increase in purchased power partially offset by a decrease in the average cost of fuel. Fuel and other cost recovery revenues decreased year-to-date 2015 when compared to the corresponding period in 2014 primarily due to a decrease in KWH generation and a decrease in the average cost of fuel.

Electric rates include provisions to recognize the full recovery of fuel costs, purchased power costs, PPAs certificated by the Alabama PSC, and costs associated with the natural disaster reserve. Under these provisions, fuel and other cost recovery revenues generally equal fuel and other cost recovery expenses and do not affect net income.

Wholesale Revenues – Non-Affiliates

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(8)	(12.3)	$(27)	(18.0)

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of Alabama Power's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. 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 the second quarter 2015, wholesale revenues from sales to non-affiliates were $57 million compared to $65 million for the corresponding period in 2014. The decrease was primarily due to a 12.0% decrease in KWH sales. For year-to-date 2015, wholesale revenues from sales to non-affiliates were $123 million compared to $150 million for the corresponding period in 2014. The decrease was primarily due to a 10.3% decrease in KWH sales and an 8.7% decrease in the price of energy.

In 2014, Alabama Power's fuel diversity led to increased sales to non-affiliates due to higher natural gas prices. In 2015, lower natural gas prices and decreased availability of hydro generation, due to less rainfall, resulted in lower sales of Alabama Power's generation to non-affiliates.

Wholesale Revenues – Affiliates

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(48)	(70.6)	$(102)	(74.5)

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

In the second quarter 2015, wholesale revenues from sales to affiliates were $20 million compared to $68 million for the corresponding period in 2014. The decrease was primarily due to a 57.4% decrease in KWH sales and a 31.1% decrease in the price of energy. For year-to-date 2015, wholesale revenues from sales to affiliates were $35 million compared to $137 million for the corresponding period in 2014. The decrease was primarily due to a 63.0% decrease in KWH sales and a 31.4% decrease in the price of energy.

In 2014, Alabama Power's fuel diversity led to increased sales to affiliates due to higher natural gas prices. In 2015, lower natural gas prices and decreased availability of hydro generation, due to less rainfall, resulted in lower sales of Alabama Power's generation to affiliates.

Fuel and Purchased Power Expenses

	Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
	(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
Fuel	$ (71)	(17.1)	$ (193)	(22.8)
Purchased power – non-affiliates	6	15.4	(10)	(10.4)
Purchased power – affiliates	12	32.4	17	19.8
Total fuel and purchased power expenses	$ (53)		$ (186)	

In the second quarter 2015, total fuel and purchased power expenses were $437 million compared to $490 million for the corresponding period in 2014. The decrease was primarily due to a $52 million decrease in the average cost of fuel, an $18 million decrease related to the volume of KWHs generated, and a $7 million decrease in the average cost of purchased power, partially offset by a $24 million increase in the volume of KWHs purchased.

For year-to-date 2015, fuel and purchased power expenses were $842 million compared to $1.03 billion for the corresponding period in 2014. The decrease was primarily due to a $120 million decrease in the average cost of fuel, a $72 million decrease related to the volume of KWHs generated, and a $44 million decrease in the average cost of purchased power, partially offset by a $50 million increase in the volume of KWHs purchased.

Fuel and purchased power energy transactions do not have a significant impact on earnings since energy expenses are generally offset by energy revenues through Alabama Power's energy cost recovery clause. Alabama Power, 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 of Alabama Power under "Retail Regulatory Matters – Rate ECR" in Item 8 of the Form 10-K for additional information.

Details of Alabama Power's generation and purchased power were as follows:

	Second Quarter 2015	Second Quarter 2014	**Year-to-Date 2015**	Year-to-Date 2014
Total generation *(billions of KWHs)*	**15**	16	**29**	33
Total purchased power *(billions of KWHs)*	**2**	1	**4**	3
Sources of generation *(percent)* —				
Coal	**59**	53	**53**	53
Nuclear	**20**	24	**23**	23
Gas	**15**	16	**17**	16
Hydro	**6**	7	**7**	8
Cost of fuel, generated *(cents per net KWH)* —				
Coal	**2.89**	3.30	**2.89**	3.35
Nuclear	**0.82**	0.85	**0.81**	0.86
Gas	**3.10**	3.80	**3.06**	3.99
Average cost of fuel, generated *(cents per net KWH)*[(a)]	**2.50**	2.76	**2.41**	2.83
Average cost of purchased power *(cents per net KWH)*[(b)]	**5.48**	5.88	**5.00**	6.18

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

(b) Average cost of purchased power includes fuel purchased by Alabama Power for tolling agreements where power is generated by the provider.

Fuel

In the second quarter 2015, fuel expense was $343 million compared to $414 million for the corresponding period in 2014. The decrease was primarily due to an 18.4% decrease in the average cost of natural gas per KWH generated, which excludes fuel associated with tolling agreements, a 14.6% decrease in the volume of KWHs generated by natural gas, and a 12.3% decrease in the average cost of coal per KWH generated. The decrease was partially offset by a 21.4% decrease in the volume of KWHs generated by hydro facilities as a result of less rainfall.

For year-to-date 2015, fuel expense was $653 million compared to $846 million for the corresponding period in 2014. The decrease was primarily due to a 23.3% decrease in the average cost of natural gas per KWH generated, which excludes fuel associated with tolling agreements, a 13.7% decrease in the average cost of coal per KWH generated, and a 9.6% decrease in the volume of KWHs generated by coal. The decrease was partially offset by a 22.1% decrease in the volume of KWHs generated by hydro facilities as a result of less rainfall.

Purchased Power – Non-Affiliates

In the second quarter 2015, purchased power expense from non-affiliates was $45 million compared to $39 million for the corresponding period in 2014. The increase was related to a 20.7% increase in the amount of energy purchased due to the availability of lower cost generation resulting from lower natural gas prices, decreased availability of hydro generation as a result of less rainfall, and increased customer demand due to warmer weather in the second quarter 2015 as compared to the corresponding period during 2014. The increase was partially offset by a 5.7% decrease in the average cost per KWH purchased as a result of lower natural gas prices.

For year-to-date 2015, purchased power expense from non-affiliates was $86 million compared to $96 million for the corresponding period in 2014. The decrease was related to a 21.9% decrease in the average cost per KWH purchased as a result of lower natural gas prices partially offset by a 13.6% increase in the amount of energy purchased due to the availability of lower cost generation as a result of 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 service territory, and the availability of the Southern Company system's generation.

Purchased Power – Affiliates

In the second quarter 2015, purchased power expense from affiliates was $49 million compared to $37 million for the corresponding period in 2014. The increase was related to a 45.2% increase in the amount of energy purchased primarily due to the availability of Southern Company's lower cost generation sources and the decreased availability of hydro generation as a result of less rainfall. The increase was partially offset by a 7.0% decrease in the average cost per KWH purchased due to lower natural gas prices.

For year-to-date 2015, purchased power expense from affiliates was $103 million compared to $86 million for the corresponding period in 2014. The increase was related to a 39.5% increase in the amount of energy purchased primarily due to the availability of Southern Company's lower cost generation sources and the decreased availability of hydro generation as a result of less rainfall. The increase was partially offset by a 14.2% decrease in the average cost per KWH purchased due to lower natural gas prices.

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

Other Operations and Maintenance Expenses

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$40	12.1	$113	17.3

In the second quarter 2015, other operations and maintenance expenses were $370 million compared to $330 million for the corresponding period in 2014. The increase was primarily due to the implementation of an accounting order in 2014 allowing the deferral of non-nuclear outage costs. Alabama Power deferred approximately $16 million of non-nuclear outage expenditures in the second quarter 2014. In addition, employee benefits including pension costs increased $11 million and steam generation costs increased $5 million primarily due to non-outage and maintenance costs.

For year-to-date 2015, other operations and maintenance expenses were $768 million compared to $655 million for the corresponding period in 2014. Alabama Power deferred approximately $41 million of non-nuclear outage expenditures in the first half of 2014. In addition, steam generation costs increased $28 million primarily due to scheduled outage costs and employee benefits including pension costs increased $21 million.

See Note 3 to the financial statements of Alabama Power under "Retail Regulatory Matters – Cost of Removal Accounting Order" in Item 8 of the Form 10-K for additional information. See Note (F) to the Condensed Financial Statements herein for additional information related to pension costs.

Depreciation and Amortization

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(12)	(7.0)	$(29)	(8.4)

In the second quarter 2015, depreciation and amortization was $160 million compared to $172 million for the corresponding period in 2014. For year-to-date 2015, depreciation and amortization was $318 million compared to $347 million for the corresponding period in 2014. These decreases were primarily due to a decrease in depreciation rates related to environmental, steam generation, transmission, and distribution assets effective January 1, 2015, as authorized by the FERC, partially offset by increases in plant in service.

Allowance for Equity Funds Used During Construction

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$3	27.3	$8	38.1

In the second quarter 2015, AFUDC equity was $14 million compared to $11 million for the corresponding period in 2014. For year-to-date 2015, AFUDC equity was $29 million compared to $21 million for the corresponding period in 2014. These increases were primarily due to additional capital expenditures for steam power environmental projects.

Interest Expense, Net of Amounts Capitalized

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$6	9.5	$9	7.2

In the second quarter 2015, interest expense, net of amounts capitalized was $69 million compared to $63 million for the corresponding period in 2014. For year-to-date 2015, interest expense, net of amounts capitalized was $134 million compared to $125 million for the corresponding period in 2014. These increases were primarily due to new debt issuances, which include issuances to redeem long-term debt, preferred stock, and preference stock.

Other Income (Expense), Net

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(11)	N/M	$(10)	(125.0)

N/M - Not meaningful

In the second quarter 2015, other income (expense), net was $(14) million compared to $(3) million for the corresponding period in 2014. For year-to-date 2015, other income (expense), net was $(18) million compared to $(8) million for the corresponding period in 2014. The changes were primarily due to increases in donations.

Income Taxes

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$3	2.5	$(11)	(4.5)

In the second quarter 2015, income taxes were $122 million compared to $119 million for the corresponding period in 2014. The increase was primarily due to higher pre-tax earnings, partially offset by state income tax credits.

For year-to-date 2015, income taxes were $235 million compared to $246 million for the corresponding period in 2014. The decrease was primarily due to state income tax credits in the second quarter 2015.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Alabama Power's future earnings potential. The level of Alabama Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Alabama Power's primary business of selling electricity. These factors include Alabama Power's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, new energy contracts with other utilities, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in Alabama Power's service territory. Changes in regional and global economic conditions may impact sales for Alabama Power as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Alabama Power in Item 7 of the Form 10-K.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Alabama Power in Item 7 and Note 3 to the financial statements of Alabama Power under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

New Source Review Actions

See Note 3 to the financial statements of Alabama Power under "Environmental Matters – New Source Review Actions" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements herein for additional information.

On June 25, 2015, the U.S. Department of Justice filed a joint stipulation between Alabama Power, the EPA, and the U.S. Department of Justice proposing to modify the 2006 consent decree to resolve all remaining claims for relief alleged in the case. If approved by the U.S. District Court for the Northern District of Alabama, Alabama Power will, without admitting liability, operate subject to emission rates and a cap on certain units and requirements to use only natural gas at certain units, including a unit co-owned by Mississippi Power; retire certain units at Plants Gorgas and Barry; pay a $100,000 civil penalty; and invest $1.5 million in electric transportation infrastructure projects over three years.

The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and – "Retail Regulatory Matters – Environmental Accounting Order" of Alabama Power in Item 7 of the Form 10-K and "Retail Regulatory Matters – Environmental Accounting Order" herein for additional information regarding Alabama Power's plan for compliance with environmental statutes and regulations.

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Alabama Power in Item 7 of the Form 10-K for additional information regarding the EPA's proposed regulations governing emissions during startup, shutdown, or malfunction (SSM), the final MATS rule, and the Cross State Air Pollution Rule (CSAPR).

On June 12, 2015, the EPA published a final rule requiring affected states (including Alabama) to revise or remove state implementation plan (SIP) provisions regarding excess emissions that occur during periods of SSM by no later than November 22, 2016. The ultimate impact of the final rule will depend on the outcome of any legal challenges and the development and approval of SIPs by the affected states and cannot be determined at this time.

On June 29, 2015, the U.S. Supreme Court issued a decision finding that the EPA had failed to properly consider costs in its decision to regulate hazardous air pollutant emissions from electric generating units under the MATS rule and remanded the case to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The MATS rule remains in effect while the U.S. Court of Appeals for the District of Columbia Circuit and the EPA respond to the decision. The ultimate impact of this decision cannot be determined at this time.

On July 28, 2015, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion invalidating certain emissions budgets under the CSAPR Phase II emissions trading program for a number of states, including Alabama. The court's decision leaves the emissions trading program in place and remands the rule to the EPA for further action consistent with the court's decision. The court rejected all other pending challenges to the rule. The ultimate impact of this decision will depend on additional rulemaking and cannot be determined at this time.

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Alabama Power in Item 7 of the Form 10-K for additional information regarding the EPA's and the U.S. Army Corps of Engineers' proposed rule revising the definition of waters of the U.S. under the Clean Water Act (CWA).

On June 29, 2015, the EPA and the U.S. Army Corps of Engineers jointly published a final rule revising the regulatory definition of waters of the U.S. for all 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 becomes effective August 28, 2015. The ultimate impact of the final rule will depend on the outcome of any legal challenges and the EPA's and the U.S. Army Corps of Engineers' field-level implementation of the rule and cannot be determined at this time.

Coal Combustion Residuals

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Coal Combustion Residuals" of Alabama Power in Item 7 of the Form 10-K for additional information regarding the EPA's regulation of CCR.

On April 17, 2015, the EPA published the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule) in the Federal Register, setting October 19, 2015 as the effective date of the CCR Rule. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on Alabama Power's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. Based on initial estimates, Alabama Power recorded incremental asset retirement obligations (ARO) of approximately $401 million related to the CCR Rule in the second quarter 2015. As further analysis is performed, including evaluation of the expected timing and method of compliance and refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, Alabama Power expects to periodically update these estimates. See Note (A) to the Condensed Financial Statements herein for additional information regarding Alabama Power's AROs.

Global Climate Issues

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" of Alabama Power in Item 7 of the Form 10-K for additional information regarding the EPA's proposed regulation of CO_2 from fossil-fuel-fired electric generating units.

On August 3, 2015, the EPA released pre-publication versions of two final rules that would limit CO_2 emissions from fossil fuel-fired electric generating units. One of the final rules contains specific emission standards governing CO_2 emissions from new, modified, and reconstructed units. The other final rule 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. At the same time, the EPA also proposed a federal plan and proposed model rule that states can adopt or that would be put in place if, in response to the final guidelines, a state either does not submit a state plan or its plan is not approved by the EPA. 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. Alabama Power's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through market-based contracts. However, the ultimate financial and operational impact of the final rules on Alabama Power cannot be determined at this time and will depend on numerous factors including the Southern Company system's ongoing review of the final rules; the outcome of any 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; the impact of future changes in generation and emissions related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

FERC Matters

Alabama Power has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional operating companies (including Alabama Power) and Southern Power filed a triennial market power analysis on June 30, 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional operating companies' (including Alabama Power's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional operating companies and in some adjacent areas. To retain market-based rate authority, the FERC directed the traditional operating companies (including Alabama Power) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional operating companies (including Alabama Power) and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

See REGULATION – "Federal Power Act" of Alabama Power in Item 1 of the Form 10-K for additional information regarding Alabama Power's Warrior River Project license.

On January 30, 2015, the U.S. Court of Appeals for the District of Columbia Circuit issued an order denying Smith Lake Improvement and Stakeholders Association's (SLISA) petition for en banc review of the court's dismissal of SLISA's appeal of the new Warrior River Project license. SLISA did not appeal this decision; therefore, this matter is now concluded and the FERC license is authorized as issued.

Retail Regulatory Matters

Alabama Power's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Alabama PSC. Alabama Power currently recovers its costs from the regulated retail business

primarily through its Rate RSE, Rate CNP, rate energy cost recovery, and natural disaster reserve rate. In addition, the Alabama PSC issues accounting orders to address current events impacting Alabama Power. See Note 1 to the financial statements of Alabama Power under "Nuclear Outage Accounting Order" and Note 3 under "Retail Regulatory Matters" in Item 8 of the Form 10-K for additional information regarding Alabama Power's rate mechanisms and accounting orders. The recovery balance of each regulatory clause for Alabama Power is reported in Note (B) to the Condensed Financial Statements herein.

Rate CNP

See Note 3 to the financial statements of Alabama Power under "Retail Regulatory Matters – Rate CNP" and " – Non-Environmental Federal Mandated Costs Accounting Order" in Item 8 of the Form 10-K for additional information regarding Alabama Power's development of a revised cost recovery mechanism and the normal purchases and normal sales (NPNS) exception for wind PPAs.

On March 3, 2015, the Alabama PSC approved a modification to Rate CNP Environmental to include compliance costs for both environmental and non-environmental mandates. The recoverable non-environmental compliance costs result from laws, regulations, and other mandates directed at the utility industry involving the security, reliability, safety, sustainability, or similar considerations impacting Alabama Power's facilities or operations. This modification to Rate CNP Environmental was effective March 20, 2015 with the revised rate now defined as Rate CNP Compliance. Alabama Power incurred $30 million of non-environmental compliance costs during the first six months of 2015 and will be limited to recovery of $50 million for the year. Customer rates will not be impacted before January 2016; therefore, the modification will increase the under recovered position for Rate CNP Compliance during 2015.

In April 2015, the Financial Accounting Standards Board (FASB) proposed new accounting guidance to allow the NPNS exception for physical forward transactions in nodal energy markets, consistent with the manner in which Alabama Power currently accounts for its two wind PPAs. On July 9, 2015, the FASB ratified the consensus reached by the Emerging Issues Task Force to allow the exception in such cases and voted to issue a final accounting standard.

Environmental Accounting Order

In April 2015, as part of its environmental compliance strategy, Alabama Power retired Plant Gorgas Units 6 and 7. These units represented 200 MWs of Alabama Power's approximately 12,200 MWs of generating capacity. 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. No later than April 2016, Alabama Power expects to cease using coal at Plant Greene County Units 1 and 2 (300 MWs) and begin operating those units solely on natural gas. Subject to the final approval of the New Source Review stipulation, Alabama Power will also retire Plant Barry Unit 3 (225 MWs) which is currently unavailable for generation. See Note (B) to the Condensed Financial Statements herein for additional information regarding the New Source Review actions.

In accordance with an 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 over the remaining useful lives, as established prior to the decision for retirement. As a result, these decisions will not have a significant impact on Alabama Power's financial statements.

Renewable Energy

On June 25, 2015, Alabama Power filed a petition with the Alabama PSC for a Renewable Generation Certificate (RGC). The RGC would develop a process that allows Alabama Power to build its own renewable projects each less than 80 MWs or purchase power from other renewable-generated sources up to 500 MWs. The Alabama PSC is expected to rule on this matter in August 2015. The ultimate outcome of this matter cannot be determined at this time.

Other Matters

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

The ultimate outcome of such pending or potential litigation against Alabama Power cannot be predicted at this time; however, for current proceedings not specifically reported in Note (B) to the Condensed Financial Statements herein or in Note 3 to the financial statements of Alabama Power in Item 8 of the Form 10-K, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Alabama Power's financial statements. See Note (B) to the Condensed Financial Statements herein for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Alabama Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Alabama Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Alabama Power's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Alabama Power in Item 7 of the Form 10-K for a complete discussion of Alabama Power's critical accounting policies and estimates related to Electric Utility Regulation, Contingent Obligations, and Pension and Other Postretirement Benefits.

Asset Retirement Obligations

AROs are computed as the fair value of the 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 Alabama Power's nuclear facility, Plant Farley, and facilities that are subject to the CCR Rule, primarily ash ponds. In addition, Alabama Power has retirement obligations related to various landfill sites, underground storage tanks, asbestos removal, disposal of polychlorinated biphenyls in certain transformers, and disposal of sulfur hexafluoride gas in certain substation breakers. Alabama Power 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.

On April 17, 2015, the EPA published the final CCR Rule in the Federal Register, setting October 19, 2015 as the effective date of the CCR Rule. Therefore, Alabama Power recorded new AROs for facilities that are subject to the CCR Rule. The cost estimates are based on information that was known as of June 30, 2015 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. As further analysis is performed, including evaluation of the expected timing and method of compliance and refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, Alabama Power expects to periodically update these estimates. Given the significant judgment involved in estimating AROs, Alabama Power considers the liabilities for AROs to be critical accounting estimates.

See Note 1 to the financial statements of Alabama Power under "Asset Retirement Obligations and Other Costs of Removal" and "Nuclear Decommissioning" in Item 8 of the Form 10-K and Note (A) to the Condensed Financial Statements under "Asset Retirement Obligations" herein for additional information.

Recently Issued Accounting Standards

The FASB's ASC 606, *Revenue from Contracts with Customers*, revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. Alabama Power continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*. The ASU requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. Alabama Power currently reflects unamortized debt issuance costs in other deferred charges and assets on its balance sheet. Upon adoption, the reclassification will not have a material impact on the results of operations, financial position, or cash flows of Alabama Power.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Overview" of Alabama Power in Item 7 of the Form 10-K for additional information. Alabama Power's financial condition remained stable at June 30, 2015. Alabama Power intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Capital Requirements and Contractual Obligations," "Sources of Capital," and "Financing Activities" herein for additional information.

Net cash provided from operating activities totaled $597 million for the first six months of 2015, a decrease of $77 million as compared to the first six months of 2014. The decrease in net cash provided from operating activities was primarily due to the timing of fossil fuel stock purchases and payments of accounts payable, partially offset by the timing of income tax payments and refunds associated with bonus depreciation. Net cash used for investing activities totaled $626 million for the first six months of 2015 primarily due to gross property additions related to distribution, environmental, transmission, and steam generation. Net cash used for financing activities totaled $49 million for the first six months of 2015 primarily due to the redemptions and repurchases of long-term debt and preferred and preference stock and payments of common stock dividends, partially offset by issuances of long-term debt. Fluctuations in cash flow from financing activities vary from period to period based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for the first six months of 2015 include increases of $690 million in property, plant, and equipment, primarily due to additions to distribution, environmental, transmission, and steam generation and $423 million in AROs associated with the CCR Rule. See Note (A) to the Condensed Financial Statements herein for additional information related to AROs. Other significant changes include decreases of $404 million in redeemable preferred and preference stock due to redemptions in the second quarter 2015.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Alabama Power in Item 7 of the Form 10-K for a

description of Alabama Power's capital requirements for its construction program, including estimated capital expenditures to comply with existing environmental statutes and regulations, scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, purchase commitments, and trust funding requirements. Approximately $600 million will be required through June 30, 2016 to fund maturities of long-term debt.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – General" of Alabama Power in Item 7 of the Form 10-K for additional information on Alabama Power's environmental compliance strategy.

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

Sources of Capital

Alabama Power plans to obtain the funds required for construction and other purposes from sources similar to those used in the past. Alabama Power has primarily utilized funds from operating cash flows, short-term debt, security issuances, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Alabama Power in Item 7 of the Form 10-K for additional information.

Alabama Power's current liabilities sometimes exceed current assets because of Alabama Power's debt due within one year and the periodic use of short-term debt as a funding source primarily to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business.

At June 30, 2015, Alabama Power had approximately $195 million of cash and cash equivalents. Committed credit arrangements with banks at June 30, 2015 were as follows:

Expires					Executable Term Loans		Due Within One Year	
2015	2016	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)			*(in millions)*		*(in millions)*		*(in millions)*	
$ 154	$ 124	$ 1,030	$ 1,308	$ 1,307	$ 58	$ —	$ 58	$ 170

See Note 6 to the financial statements of Alabama Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information.

A portion of the unused credit with banks is allocated to provide liquidity support to Alabama Power's variable rate pollution control revenue bonds and commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of June 30, 2015 was approximately $810 million. In addition, at June 30, 2015, Alabama Power had $200 million of fixed rate pollution control revenue bonds outstanding that were required to be reoffered within the next 12 months.

Most of these bank credit arrangements contain covenants that limit debt levels and contain cross default provisions to other indebtedness (including guarantee obligations) of Alabama Power. Such cross default provisions to other

indebtedness would trigger an event of default if Alabama Power defaulted on indebtedness or guarantee obligations over a specified threshold. Alabama Power is currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

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

In addition, Alabama Power has substantial cash flow from operating activities and access to capital markets, including a commercial paper program, to meet liquidity needs. Alabama Power may meet short-term cash needs through its commercial paper program. Alabama Power may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of Alabama Power and the other traditional operating companies. Proceeds from such issuances for the benefit of Alabama Power are loaned directly to Alabama Power. The obligations of each company under these arrangements are several and there is no cross-affiliate credit support.

Details of short-term borrowings were as follows:

	Short-term Debt at June 30, 2015		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)*
Commercial Paper	$ —	—%	$ 17	0.2%	$ 100

(*) Average and maximum amounts are based upon daily balances during the three-month period ended June 30, 2015.

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

Credit Rating Risk

Alabama Power does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are primarily for physical electricity purchases, fuel purchases, fuel transportation and storage, and energy price risk management. At June 30, 2015, potential collateral requirements under these contracts at a rating of BBB- and/or Baa3 were immaterial. The maximum collateral requirements at a rating below BBB- and/or Baa3 were approximately $367 million. Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash.

Subsequent to June 30, 2015, S&P placed its ratings of Southern Company and the traditional operating companies (including Alabama Power) on CreditWatch with negative implications.

Financing Activities

In March 2015, Alabama Power issued $550 million aggregate principal amount of Series 2015A 3.750% Senior Notes due March 1, 2045. The proceeds were used to redeem $250 million aggregate principal amount of Series DD 5.65% Senior Notes due March 15, 2035 and for general corporate purposes, including Alabama Power's continuous construction program.

In April 2015, Alabama Power purchased and held $80 million aggregate principal amount of Industrial Development Board of the City of Mobile, Alabama Pollution Control Revenue Bonds (Alabama Power Company Barry Plant Project), Series 2007-B. Alabama Power reoffered these bonds to the public in May 2015.

Also in April 2015, Alabama Power issued $175 million additional aggregate principal amount of its Series 2015A 3.750% Senior Notes due March 1, 2045 (Additional Series 2015A Senior Notes) and $250 million aggregate principal amount of its Series 2015B 2.800% Senior Notes due April 1, 2025 (Series 2015B Senior Notes). A portion of the proceeds of the Additional Series 2015A Senior Notes and the Series 2015B Senior Notes were used to redeem in May 2015 6.48 million shares ($162 million aggregate stated capital) of Alabama Power's 5.20% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date, 4.0 million shares ($100 million aggregate stated capital) of Alabama Power's 5.30% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date, and 6.0 million shares ($150 million aggregate stated capital) of Alabama Power's 5.625% Series Preference Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date, and the remaining net proceeds were used for general corporate purposes, including Alabama Power's continuous construction program.

In June 2015, $18.7 million aggregate principal amount of the Industrial Development Board of the City of Mobile, Alabama Pollution Control Revenue Refunding Bonds (Alabama Power Company Project), Series 1994, $6.15 million aggregate principal amount of the Industrial Development Board of the City of Gadsden, Pollution Control Revenue Bonds (Alabama Power Company Project), Series 1994, and $28.85 million aggregate principal amount of the Industrial Development Board of the Town of Parrish, Pollution Control Revenue Refunding Bonds (Alabama Power Company Project), Series 1994A were repaid at maturity.

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

GEORGIA POWER COMPANY

GEORGIA POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	**2015**	2014
	(in millions)		*(in millions)*	
Operating Revenues:				
Retail revenues	**$ 1,872**	$ 2,000	**$ 3,686**	$ 4,050
Wholesale revenues, non-affiliates	**50**	80	**118**	189
Wholesale revenues, affiliates	**4**	10	**12**	31
Other revenues	**90**	96	**178**	185
Total operating revenues	**2,016**	2,186	**3,994**	4,455
Operating Expenses:				
Fuel	**503**	619	**1,029**	1,371
Purchased power, non-affiliates	**78**	63	**138**	142
Purchased power, affiliates	**115**	166	**263**	350
Other operations and maintenance	**467**	451	**943**	878
Depreciation and amortization	**202**	209	**418**	417
Taxes other than income taxes	**97**	106	**195**	209
Total operating expenses	**1,462**	1,614	**2,986**	3,367
Operating Income	**554**	572	**1,008**	1,088
Other Income and (Expense):				
Interest expense, net of amounts capitalized	**(93)**	(90)	**(182)**	(174)
Other income (expense), net	**1**	11	**16**	15
Total other income and (expense)	**(92)**	(79)	**(166)**	(159)
Earnings Before Income Taxes	**462**	493	**842**	929
Income taxes	**180**	177	**320**	343
Net Income	**282**	316	**522**	586
Dividends on Preferred and Preference Stock	**5**	5	**9**	9
Net Income After Dividends on Preferred and Preference Stock	**$ 277**	$ 311	**$ 513**	$ 577

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	**2015**	2014
	(in millions)		*(in millions)*	
Net Income	**$ 282**	$ 316	**$ 522**	$ 586
Other comprehensive income (loss):				
Qualifying hedges:				
Changes in fair value, net of tax of $9, $-, $-, and $-, respectively	**14**	—	—	—
Reclassification adjustment for amounts included in net income, net of tax of $-, $-, $1, and $-, respectively	**1**	1	**1**	1
Total other comprehensive income (loss)	**15**	1	**1**	1
Comprehensive Income	**$ 297**	$ 317	**$ 523**	$ 587

The accompanying notes as they relate to Georgia Power are an integral part of these condensed financial statements.

GEORGIA POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Six Months Ended June 30,	
	2015	2014
	(in millions)	
Operating Activities:		
Net income	**$ 522**	$ 586
Adjustments to reconcile net income to net cash provided from operating activities —		
Depreciation and amortization, total	**512**	503
Deferred income taxes	**(6)**	121
Allowance for equity funds used during construction	**(10)**	(16)
Retail fuel cost over recovery — long-term	**—**	(44)
Deferred expenses	**28**	31
Contract amendment	**(118)**	—
Other, net	**—**	(12)
Changes in certain current assets and liabilities —		
-Receivables	**(21)**	(353)
-Fossil fuel stock	**101**	255
-Prepaid income taxes	**86**	(7)
-Other current assets	**(38)**	(14)
-Accounts payable	**(110)**	(140)
-Accrued taxes	**(125)**	(65)
-Accrued compensation	**(61)**	(15)
-Retail fuel cost over recovery — short-term	**—**	(14)
-Other current liabilities	**14**	27
Net cash provided from operating activities	**774**	843
Investing Activities:		
Property additions	**(853)**	(906)
Nuclear decommissioning trust fund purchases	**(655)**	(324)
Nuclear decommissioning trust fund sales	**649**	322
Change in construction payables, net of joint owner portion	**26**	52
Prepaid long-term service agreements	**(40)**	(47)
Other investing activities	**(18)**	(14)
Net cash used for investing activities	**(891)**	(917)
Financing Activities:		
Increase (decrease) in notes payable, net	**44**	(359)
Proceeds —		
Capital contributions from parent company	**23**	24
Pollution control revenue bonds	**170**	—
FFB loan	**600**	1,000
Short-term borrowings	**250**	—
Redemptions and repurchases —		
Pollution control revenue bonds	**(65)**	(37)
Senior notes	**(125)**	—
Short-term borrowings	**(250)**	—
Payment of preferred and preference stock dividends	**(9)**	(9)
Payment of common stock dividends	**(517)**	(477)
FFB loan issuance costs	**—**	(49)
Other financing activities	**(4)**	(3)
Net cash provided from financing activities	**117**	90
Net Change in Cash and Cash Equivalents	**—**	16
Cash and Cash Equivalents at Beginning of Period	**24**	30
Cash and Cash Equivalents at End of Period	**$ 24**	$ 46
Supplemental Cash Flow Information:		
Cash paid during the period for —		
Interest (net of $5 and $8 capitalized for 2015 and 2014, respectively)	**$ 170**	$ 157
Income taxes, net	**240**	145
Noncash transactions — Accrued property additions at end of period	**171**	267

The accompanying notes as they relate to Georgia Power are an integral part of these condensed financial statements.

GEORGIA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Assets	At June 30, 2015	At December 31, 2014
	(in millions)	
Current Assets:		
Cash and cash equivalents	$ 24	$ 24
Receivables —		
Customer accounts receivable	778	553
Unbilled revenues	294	201
Joint owner accounts receivable	44	121
Other accounts and notes receivable	46	61
Affiliated companies	20	18
Accumulated provision for uncollectible accounts	(6)	(6)
Fossil fuel stock, at average cost	338	439
Materials and supplies, at average cost	425	438
Vacation pay	91	91
Prepaid income taxes	225	278
Other regulatory assets, current	147	136
Other current assets	86	74
Total current assets	2,512	2,428
Property, Plant, and Equipment:		
In service	31,363	31,083
Less accumulated provision for depreciation	10,961	11,222
Plant in service, net of depreciation	20,402	19,861
Other utility plant, net	10	211
Nuclear fuel, at amortized cost	551	563
Construction work in progress	4,171	4,031
Total property, plant, and equipment	25,134	24,666
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	61	58
Nuclear decommissioning trusts, at fair value	814	789
Miscellaneous property and investments	37	38
Total other property and investments	912	885
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	681	698
Deferred under recovered regulatory clause revenues	—	197
Other regulatory assets, deferred	2,063	1,753
Other deferred charges and assets	446	403
Total deferred charges and other assets	3,190	3,051
Total Assets	$ 31,748	$ 31,030

The accompanying notes as they relate to Georgia Power are an integral part of these condensed financial statements.

GEORGIA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	At June 30, 2015	At December 31, 2014
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 1,660**	$ 1,154
Notes payable	**200**	156
Accounts payable —		
Affiliated	**392**	451
Other	**574**	555
Customer deposits	**259**	253
Other accrued taxes	**207**	332
Accrued interest	**96**	96
Accrued vacation pay	**62**	63
Accrued compensation	**81**	153
Other current liabilities	**309**	257
Total current liabilities	**3,840**	3,470
Long-term Debt	**8,914**	8,683
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**5,524**	5,507
Deferred credits related to income taxes	**103**	106
Accumulated deferred investment tax credits	**191**	196
Employee benefit obligations	**870**	903
Asset retirement obligations	**1,301**	1,223
Other deferred credits and liabilities	**286**	255
Total deferred credits and other liabilities	**8,275**	8,190
Total Liabilities	**21,029**	20,343
Preferred Stock	**45**	45
Preference Stock	**221**	221
Common Stockholder's Equity:		
Common stock, without par value —		
Authorized — 20,000,000 shares		
Outstanding — 9,261,500 shares	**398**	398
Paid-in capital	**6,232**	6,196
Retained earnings	**3,830**	3,835
Accumulated other comprehensive loss	**(7)**	(8)
Total common stockholder's equity	**10,453**	10,421
Total Liabilities and Stockholder's Equity	**$ 31,748**	$ 31,030

The accompanying notes as they relate to Georgia Power are an integral part of these condensed financial statements.

OVERVIEW

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

Many factors affect the opportunities, challenges, and risks of Georgia Power's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, and fuel. In addition, construction continues on Plant Vogtle Units 3 and 4 in which Georgia Power will own a 45.7% interest in these two nuclear generating units to increase its generation diversity and meet future supply needs. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge Georgia Power for the foreseeable future.

Georgia Power continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, the execution of major construction projects, and net income after dividends on preferred and preference stock. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Key Performance Indicators" of Georgia Power in Item 7 of the Form 10-K.

RESULTS OF OPERATIONS

Net Income

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(34)	(10.9)	$(64)	(11.1)

Georgia Power's net income after dividends on preferred and preference stock for the second quarter 2015 was $277 million compared to $311 million for the corresponding period in 2014. For year-to-date 2015, net income after dividends on preferred and preference stock was $513 million compared to $577 million for the corresponding period in 2014. The decreases were primarily due to higher non-fuel operations and maintenance expenses and the correction of an error affecting billings to a small number of large commercial and industrial customers, partially offset by increases in retail base revenues effective January 1, 2015 as authorized by the Georgia PSC. Additionally, warmer weather in the second quarter 2015 compared to the corresponding period in 2014 contributed to increases in retail base revenues.

See Note (A) to Condensed Financial Statements herein for additional information.

Retail Revenues

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(128)	(6.4)	$(364)	(9.0)

In the second quarter 2015, retail revenues were $1.87 billion compared to $2.00 billion for the corresponding period in 2014. For year-to-date 2015, retail revenues were $3.69 billion compared to $4.05 billion for the corresponding period in 2014.

Details of the changes in retail revenues were as follows:

	Second Quarter 2015		Year-to-Date 2015	
	(in millions)	*(% change)*	*(in millions)*	*(% change)*
Retail – prior year	$ 2,000		$ 4,050	
Estimated change resulting from –				
Rates and pricing	(27)	(1.3)	3	0.1
Sales growth	21	1.0	37	0.9
Weather	22	1.1	6	0.1
Fuel cost recovery	(144)	(7.2)	(410)	(10.1)
Retail – current year	$ 1,872	(6.4)%	$ 3,686	(9.0)%

Revenues associated with changes in rates and pricing decreased in the second quarter 2015 when compared to the corresponding period in 2014 primarily due to the 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, partially offset by base tariff increases approved under the 2013 ARP and increases in collections for financing costs related to the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff, which were both effective January 1, 2015. Revenues associated with changes in rates and pricing increased slightly year-to-date 2015 when compared to the corresponding period in 2014 primarily due to the base tariff increases and increases in collections for financing costs described above, partially offset by the error correction. See Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Rate Plans" in Item 8 of the Form 10-K and Note (A) to the Condensed Financial Statements herein for additional information.

Revenues attributable to changes in sales increased in the second quarter and year-to-date 2015 when compared to the corresponding periods in 2014. Weather-adjusted residential KWH sales increased 2.6%, weather-adjusted commercial KWH sales increased 1.1%, and weather-adjusted industrial KWH sales remained flat in the second quarter 2015 when compared to the corresponding period in 2014. For year-to-date 2015, weather-adjusted residential KWH sales increased 1.8%, weather-adjusted commercial KWH sales increased 1.0%, and weather-adjusted industrial KWH sales increased 2.0% when compared to the corresponding period in 2014. An increase of approximately 28,000 residential customers since June 30, 2014 contributed to the increase in weather-adjusted residential KWH sales. Increased customer usage and an increase of approximately 3,000 commercial customers since June 30, 2014 contributed to the increase in weather-adjusted commercial sales. Increased demand in the paper, stone, clay, and glass, food processing, transportation, rubber, and pipeline sectors was the main contributor to the increase in weather-adjusted industrial KWH sales, partially offset by a decrease in the chemicals sector.

Fuel revenues and costs are allocated between retail and wholesale jurisdictions. Retail fuel cost recovery revenues decreased $144 million and $410 million in the second quarter and year-to-date 2015, respectively, when compared to the corresponding periods in 2014 primarily due to lower natural gas, coal, and nuclear fuel costs. 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 – Non-Affiliates

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(30)	(37.5)	$(71)	(37.6)

Wholesale revenues from sales to non-affiliates consist of PPAs and short-term opportunity sales. Wholesale revenues from PPAs have both capacity and energy components. 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 Georgia Power's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. 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 Georgia Power's variable cost of energy.

In the second quarter 2015, wholesale revenues from sales to non-affiliates were $50 million compared to $80 million for the corresponding period in 2014 related to a $15 million decrease in energy revenues and a $15 million decrease in capacity revenues. For year-to-date 2015, wholesale revenues from sales to non-affiliates were $118 million compared to $189 million for the corresponding period in 2014 related to a $48 million decrease in energy revenues and a $23 million decrease in capacity revenues. The decreases in energy revenues were primarily due to the lower cost of natural gas and coal. The decreases in capacity revenues reflect the expiration of wholesale contracts in December 2014 and the retirements of Plant Branch Units 1, 3, and 4, Plant Yates Units 1 through 5, and Plant McManus Units 1 and 2.

Wholesale Revenues – Affiliates

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(6)	(60.0)	$(19)	(61.3)

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the IIC, as approved by the FERC. These transactions do not have a significant impact on earnings since the energy is generally sold at marginal cost.

In the second quarter 2015, wholesale revenues from sales to affiliates were $4 million compared to $10 million for the corresponding period in 2014. For year-to-date 2015, wholesale revenues from sales to affiliates were $12 million compared to $31 million for the corresponding period in 2014. The decreases were due to lower natural gas and coal prices.

Fuel and Purchased Power Expenses

	Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
	(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
Fuel	$ (116)	(18.7)	$ (342)	(24.9)
Purchased power – non-affiliates	15	23.8	(4)	(2.8)
Purchased power – affiliates	(51)	(30.7)	(87)	(24.9)
Total fuel and purchased power expenses	$ (152)		$ (433)	

In the second quarter 2015, total fuel and purchased power expenses were $696 million compared to $848 million in the corresponding period in 2014. The decrease in the second quarter 2015 was primarily due to a $154 million decrease in the average cost of fuel related to lower natural gas, coal, and nuclear fuel prices and a decrease in the average cost of purchased power due to lower natural gas prices and a $21 million decrease in the volume of KWHs generated due to less available generating capacity as a result of plant retirements in April 2015, partially offset by a $23 million increase in the volume of KWHs purchased due to lower natural gas prices.

For year-to-date 2015, total fuel and purchased power expenses were $1.43 billion compared to $1.86 billion in the corresponding period in 2014. The decrease in year-to-date 2015 was primarily due to a $396 million decrease in the average cost of fuel related to lower natural gas, coal, and nuclear fuel prices and a decrease in the average cost of purchased power due to lower natural gas prices and a $99 million decrease in the volume of KWHs generated due to less available generating capacity as a result of plant retirements in April 2015, partially offset by a $62 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 Georgia Power's fuel cost recovery mechanism. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information.

Details of Georgia Power's generation and purchased power were as follows:

	Second Quarter 2015	Second Quarter 2014	**Year-to-Date 2015**	Year-to-Date 2014
Total generation *(billions of KWHs)*	**17**	18	**34**	36
Total purchased power *(billions of KWHs)*	**6**	5	**11**	10
Sources of generation *(percent)* —				
Coal	**40**	42	**37**	45
Nuclear	**24**	22	**23**	21
Gas	**34**	34	**38**	31
Hydro	**2**	2	**2**	3
Cost of fuel, generated *(cents per net KWH)* —				
Coal	**3.75**	4.20	**4.18**	4.65
Nuclear	**0.85**	0.93	**0.71**	0.92
Gas	**2.67**	3.81	**2.65**	4.09
Average cost of fuel, generated *(cents per net KWH)*	**2.66**	3.32	**2.76**	3.66
Average cost of purchased power *(cents per net KWH)*(*)	**4.56**	5.55	**4.47**	5.66

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

Fuel

In the second quarter 2015, fuel expense was $503 million compared to $619 million in the corresponding period in 2014. The decrease was primarily due to a 19.9% decrease in the average cost of fuel per KWH generated and a 6.7% decrease in the volume of KWHs generated by coal.

For year-to-date 2015, fuel expense was $1.03 billion compared to $1.37 billion in the corresponding period in 2014. The decrease was primarily due to a 24.6% decrease in the average cost of fuel per KWH generated and a 22.2% decrease in the volume of KWHs generated by coal, partially offset by a 13.9% increase in the volume of KWHs generated by natural gas.

Purchased Power – Non-Affiliates

In the second quarter 2015, purchased power expense from non-affiliates was $78 million compared to $63 million in the corresponding period in 2014. The increase was primarily due to a 94.1% increase in the volume of KWHs purchased to meet higher customer demand resulting from warmer weather in the second quarter 2015 compared to the corresponding period in 2014 and to replace the energy previously generated by the plants retired in April 2015,

partially offset by a 36.0% decrease in the average cost per KWH purchased, primarily resulting from lower natural gas prices.

For year-to-date 2015, purchased power expense from non-affiliates was $138 million compared to $142 million in the corresponding period in 2014. The decrease was primarily due to a 32.9% decrease in the average cost per KWH purchased primarily from lower natural gas prices, partially offset by a 48.5% increase in volume of KWHs purchased to meet higher customer demand resulting from warmer weather in the second quarter 2015 compared to the corresponding period in 2014 and to replace the energy previously generated by the plants retired in April 2015.

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

Purchased Power – Affiliates

In the second quarter 2015, purchased power expense from affiliates was $115 million compared to $166 million in the corresponding period in 2014. For year-to-date 2015, purchased power expense from affiliates was $263 million compared to $350 million in the corresponding period in 2014. The decreases were due to a 17.7% decrease in the second quarter 2015 and a 20.7% decrease for year-to-date 2015 in the average cost of KWH purchased, primarily resulting from lower natural gas prices.

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

Other Operations and Maintenance Expenses

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$16	3.5	$65	7.4

In the second quarter 2015, other operations and maintenance expenses were $467 million compared to $451 million in the corresponding period in 2014. The increase was primarily due to increases of $10 million in employee compensation and benefits including pension costs, $8 million in scheduled outage-related costs, and $3 million primarily related to customer incentive and demand-side management costs, partially offset by a decrease of $7 million in transmission and distribution overhead line maintenance. See Note (F) to the Condensed Financial Statements herein for additional information related to pension costs.

For year-to-date 2015, other operations and maintenance expenses were $943 million compared to $878 million in the corresponding period in 2014. The increase was primarily due to increases of $31 million in employee compensation and benefits including pension costs, $15 million in scheduled outage-related costs, and $13 million primarily related to customer incentive and demand-side management costs.

Depreciation and Amortization

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(7)	(3.3)	$1	0.2

In the second quarter 2015, depreciation and amortization was $202 million compared to $209 million in the corresponding period in 2014. The decrease was primarily due to decreases in other cost of removal of $9 million and depreciation of $2 million as authorized by the Georgia PSC under the 2013 ARP, partially offset by an increase in amortization of $4 million.

For year-to-date 2015, depreciation and amortization was $418 million compared to $417 million in the corresponding period in 2014. The increase was due to an increase in depreciation and amortization of $10 million as authorized by the Georgia PSC under the 2013 ARP, partially offset by a decrease in other cost of removal of $9 million.

Taxes Other Than Income Taxes

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(9)	(8.5)	$(14)	(6.7)

In the second quarter 2015, taxes other than income taxes were $97 million compared to $106 million in the corresponding period in 2014. For the year-to-date 2015, taxes other than income taxes were $195 million compared to $209 million in the corresponding period in 2014. The decreases were primarily due to decreases of $6 million and $11 million in municipal franchise fees related to lower retail revenues in the second quarter 2015 and year-to-date 2015, respectively, as well as decreases of $2 million in property taxes for each period.

Other Income (Expense), net

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(10)	(90.9)	$1	6.6

In the second quarter 2015, other income (expense), net was $1 million compared to $11 million in the corresponding period in 2014. For year-to-date 2015, other income (expense), net was $16 million compared to $15 million in the corresponding period in 2014. The changes primarily relate to AFUDC equity.

Income Taxes

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$3	1.7	$(23)	(6.7)

For year-to-date 2015, income taxes were $320 million compared to $343 million in the corresponding period in 2014. The decrease was primarily due to lower pre-tax earnings.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Georgia Power's future earnings potential. The level of Georgia Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Georgia Power's business of selling electricity. These factors include Georgia Power's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and the completion and subsequent operation of ongoing construction projects, primarily Plant Vogtle Units 3 and 4. Future earnings in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, new energy contracts with other utilities, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in Georgia Power's service territory. Changes in regional and global economic conditions may impact sales for Georgia Power as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Georgia Power in Item 7 of the Form 10-K.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Georgia Power's Environmental Compliance Cost Recovery (ECCR) tariff allows for the recovery of capital and operations and maintenance costs related to environmental controls mandated by state and federal regulations. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Georgia Power in Item 7 and Note 3 to the financial statements of Georgia Power under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

Environmental Statutes and Regulations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Integrated Resource Plans" of Georgia Power in Item 7 of the Form 10-K and "Retail Regulatory Matters – Integrated Resource Plan" herein for additional information on planned unit retirements and fuel conversions at Georgia Power.

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Georgia Power in Item 7 of the Form 10-K for additional information regarding the EPA's proposed regulations governing emissions during startup, shutdown, or malfunction (SSM), the final MATS rule, and the Cross State Air Pollution Rule (CSAPR).

On June 12, 2015, the EPA published a final rule requiring affected states (including Georgia, Alabama, and Florida) to revise or remove state implementation plan (SIP) provisions regarding excess emissions that occur during periods of SSM by no later than November 22, 2016. The ultimate impact of the final rule will depend on the outcome of any legal challenges and the development and approval of SIPs by the affected states and cannot be determined at this time.

On June 29, 2015, the U.S. Supreme Court issued a decision finding that the EPA had failed to properly consider costs in its decision to regulate hazardous air pollutant emissions from electric generating units under the MATS rule and remanded the case to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The MATS rule remains in effect while the U.S. Court of Appeals for the District of Columbia Circuit and the EPA respond to the decision. The ultimate impact of this decision cannot be determined at this time.

On July 28, 2015, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion invalidating certain emissions budgets under the CSAPR Phase II emissions trading program for a number of states, including Georgia, Alabama, and Florida. The court's decision leaves the emissions trading program in place and remands the rule to the EPA for further action consistent with the court's decision. The court rejected all other pending challenges to the rule. The ultimate impact of this decision will depend on additional rulemaking and cannot be determined at this time.

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Georgia Power in Item 7 of the Form 10-K for additional information regarding the EPA's and the U.S. Army Corps of Engineers' proposed rule revising the definition of waters of the U.S. under the Clean Water Act (CWA).

On June 29, 2015, the EPA and the U.S. Army Corps of Engineers jointly published a final rule revising the regulatory definition of waters of the U.S. for all 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 becomes effective August 28, 2015. The ultimate impact of the final rule will depend on the outcome of any legal challenges and the EPA's and the U.S. Army Corps of Engineers' field-level implementation of the rule and cannot be determined at this time.

Coal Combustion Residuals

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Coal Combustion Residuals" of Georgia Power in Item 7 of the Form 10-K for additional information regarding the EPA's regulation of CCR.

On April 17, 2015, the EPA published the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule) in the Federal Register, setting October 19, 2015 as the effective date of the CCR Rule. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on Georgia Power's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. Based on initial estimates, Georgia Power recorded incremental asset retirement obligations (ARO) of approximately $82 million related to the CCR Rule in the second quarter 2015. As further analysis is performed, including evaluation of the expected timing and method of compliance and refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, Georgia Power expects to periodically update these estimates. See Note (A) to the Condensed Financial Statements herein for additional information regarding Georgia Power's AROs.

Global Climate Issues

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" of Georgia Power in Item 7 of the Form 10-K for additional information regarding the EPA's proposed regulation of CO_2 from fossil-fuel-fired electric generating units.

On August 3, 2015, the EPA released pre-publication versions of two final rules that would limit CO_2 emissions from fossil fuel-fired electric generating units. One of the final rules contains specific emission standards governing CO_2 emissions from new, modified, and reconstructed units. The other final rule 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. At the same time, the EPA also proposed a federal plan and proposed model rule that states can adopt or that would be put in place if, in response to the final guidelines, a state either does not submit a state plan or its plan is not approved by the EPA. 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. Georgia Power's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through market-based contracts. However, the ultimate financial and operational impact of the final rules on Georgia Power cannot be determined at this time and will depend on numerous factors including the Southern Company system's ongoing review of the final rules; the outcome of any 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; the impact of future changes in generation and emissions related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

FERC Matters

Georgia Power has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with

FERC regulations governing such authority, the traditional operating companies (including Georgia Power) and Southern Power filed a triennial market power analysis on June 30, 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional operating companies' (including Georgia Power's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional operating companies and in some adjacent areas. To retain market-based rate authority, the FERC directed the traditional operating companies (including Georgia Power) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional operating companies (including Georgia Power) and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

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, 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 of Georgia Power under "Retail Regulatory Matters" in Item 8 of the Form 10-K for additional information.

Renewables Development

As part of the Georgia Power Advanced Solar Initiative program, Georgia Power executed ten PPAs that were approved by the Georgia PSC in 2014 and provide for the purchase of energy from 515 MWs of solar capacity. These PPAs are expected to commence in December 2015 and 2016 and have terms ranging from 20 to 30 years. As a result of certain acquisitions by Southern Power, Georgia Power expects that 249 MWs of the 515 MWs of contracted capacity will be purchased from solar facilities owned or under development by Southern Power.

On June 15, 2015, Georgia Power executed a PPA to purchase a total of 58 MWs of biomass capacity and energy from a 79-MW facility in Georgia that will begin in 2017 and end in 2047. This PPA was approved by the Georgia PSC on April 15, 2015. Georgia Power also entered into an energy-only PPA for the remaining 21 MWs from the same facility.

On July 21, 2015, the Georgia PSC approved Georgia Power's request to build, own, and operate a 46-MW solar generation facility at a U.S. Marine Corps base in Albany, Georgia by the end of 2016.

Integrated Resource Plan

To comply with the April 16, 2015 effective date of the MATS rule, Plant Branch Units 1, 3, and 4 (1,266 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) were retired on April 15, 2015. In addition, operations were discontinued at Plant Mitchell Unit 3 (155 MWs) and its decertification will be requested in connection with the triennial Integrated Resource Plan in 2016. The switch to natural gas as the primary fuel is complete at Plant Yates Units 7 and 6 and the units were returned to service on May 4, 2015 and June 27, 2015, respectively.

Fuel Cost Recovery

Georgia Power has established fuel cost recovery rates approved by the Georgia PSC. Georgia Power expects to file its next fuel case in September 2015. The ultimate outcome of this matter cannot be determined at this time.

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 Georgia Power's revenues or net income, but will affect cash flow. See Note (B) to the Condensed Financial Statements under "Retail Regulatory Matters – Georgia Power – Fuel Cost Recovery" herein for additional information.

Nuclear Construction

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" of Georgia Power in Item 7 and Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Nuclear Construction" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" herein for additional information regarding the construction of Plant Vogtle Units 3 and 4, Vogtle Construction Monitoring (VCM) reports, and pending litigation.

In 2008, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into an agreement (Vogtle 3 and 4 Agreement) with the Contractor, pursuant to which the Contractor agreed to design, engineer, procure, construct, and test Plant Vogtle Units 3 and 4. Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price that is 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. The Contractor's liability to the Vogtle Owners for schedule and performance liquidated damages and warranty claims is subject to a cap. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which have not 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%.

Certain payment obligations of Westinghouse and CB&I Stone & Webster, Inc. (formerly known as Stone & Webster, Inc.) under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group Inc. (a subsidiary of Chicago Bridge & Iron Company, N.V.), respectively. 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. The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay certain termination costs. 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 2009, the NRC issued an Early Site Permit and Limited Work Authorization which allowed limited work to begin on Plant Vogtle Units 3 and 4. The NRC certified the Westinghouse Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, in late 2011, and issued combined construction and operating licenses (COLs) in early 2012. Receipt of the COLs allowed full construction to begin. 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 are expected as construction proceeds.

In 2012, the Vogtle Owners and the Contractor began negotiations regarding the costs associated with design changes to the DCD and the delays in the timing of approval of the DCD and issuance of the COLs, including the assertion by the Contractor that the Vogtle Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. Also in 2012, Georgia Power and the other Vogtle Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Vogtle Owners are not responsible for these costs. In 2012, the Contractor also filed suit against Georgia Power and the other Vogtle Owners in the U.S. District Court for the District of Columbia alleging the Vogtle Owners are responsible for these costs. In 2013, the U.S. District Court for the District of Columbia dismissed the Contractor's suit, ruling that the proper venue is the U.S. District Court for the Southern District of Georgia. On March 10, 2015, the U.S. Court of Appeals for the District of Columbia Circuit affirmed the District Court's decision. The portion of additional costs claimed by the Contractor in its initial complaint that would be attributable to Georgia Power (based on Georgia Power's ownership interest) is approximately $425 million in 2008 dollars (approximately $591 million in 2015 dollars). The Contractor also asserted it is entitled to extensions of the guaranteed substantial completion dates of

April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. In May 2014, the Contractor filed an amended counterclaim to the suit pending in the U.S. District Court for the Southern District of Georgia alleging that (i) the design changes to the DCD imposed by the NRC delayed module production and the impacts to the Contractor are recoverable by the Contractor under the Vogtle 3 and 4 Agreement and (ii) the changes to the basemat rebar design required by the NRC caused additional costs and delays recoverable by the Contractor under the Vogtle 3 and 4 Agreement. The Contractor did not specify in its amended counterclaim the amounts relating to these new allegations; however, the Contractor subsequently asserted estimated minimum damages related to the amended counterclaim (based on Georgia Power's ownership interest) of approximately $113 million in 2014 dollars (approximately $118 million in 2015 dollars). In June 2015, the Contractor updated its estimated damages under the initial complaint and the amended counterclaim to an aggregate (based on Georgia Power's ownership interest) of approximately $714 million (in 2015 dollars). The Contractor may from time to time continue to assert that it is entitled to additional payments with respect to these allegations, any of which could be substantial. Georgia Power has not agreed to the proposed cost or to any changes to the guaranteed substantial completion dates or that the Vogtle Owners have any responsibility for costs related to these issues. Litigation is ongoing and Georgia Power intends to vigorously defend the positions of the Vogtle Owners. Georgia Power also expects negotiations with the Contractor to continue with respect to cost and schedule. During such negotiations the parties may reach a mutually acceptable compromise of their positions.

Georgia Power is required to file semi-annual VCM reports with the Georgia PSC by February 28 and August 31 each year. If the projected certified construction capital costs to be borne by Georgia Power increase by 5% or the projected in-service dates are significantly extended, Georgia Power is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. Georgia Power's eighth VCM report filed in 2013 requested an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 from $4.4 billion to $4.8 billion and to extend the estimated in-service dates to the fourth quarter 2017 and the fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively. In 2013, the Georgia PSC approved a stipulation (2013 Stipulation) entered into by 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. The Georgia PSC has approved eleven VCM reports covering the periods through June 30, 2014, including construction capital costs incurred, which through that date totaled $2.8 billion.

On January 29, 2015, Georgia Power announced it was notified by the Contractor of the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4, which would incrementally delay the previously disclosed estimated in-service dates by 18 months (from the fourth quarter of 2017 to the second quarter of 2019 for Unit 3 and from the fourth quarter of 2018 to the second quarter of 2020 for Unit 4).

Georgia Power believes that, pursuant to the Vogtle 3 and 4 Agreement, the Contractor is responsible for the Contractor's costs related to the Contractor's delay (including any related construction and mitigation costs, which could be material) and that the Vogtle Owners are entitled to recover liquidated damages for the Contractor's delay beyond the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. Consistent with the Contractor's position in the pending litigation described above, Georgia Power expects the Contractor to contest any claims for liquidated damages and to assert that the Vogtle Owners are responsible for additional costs related to the Contractor's delay.

On February 27, 2015, Georgia Power filed its twelfth VCM report with the Georgia PSC covering the period from July 1 through December 31, 2014, which requested approval for an additional $0.2 billion of construction capital costs incurred during that period. The twelfth VCM report also reflected the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4 as well as additional estimated owner-related costs, which include approximately $10 million per month expected to result from the Contractor's proposed 18-month delay, including property taxes, oversight costs, compliance costs, and other operational readiness costs. No Contractor costs related to the Contractor's proposed 18-month delay were included in the twelfth VCM report. Additionally, while Georgia Power has not agreed to any change to the guaranteed substantial completion dates, the twelfth VCM report included a requested amendment (Requested Amendment) to the Plant Vogtle Units 3 and 4 certificate to reflect the Contractor's revised forecast, to include the estimated owner's costs associated with the proposed 18-month

Contractor delay, and to increase the estimated total in-service capital cost of Plant Vogtle Units 3 and 4 to $5.0 billion.

Georgia Power will continue to incur financing costs of approximately $30 million per month until Plant Vogtle Units 3 and 4 are placed in service. The twelfth VCM report estimated financing costs during the construction period to total approximately $2.5 billion.

On April 15, 2015, the Georgia PSC issued a procedural order in connection with the twelfth VCM report. Pursuant to this order, the Georgia PSC deemed the Requested Amendment unnecessary and withdrawn until the completion of construction of Plant Vogtle Unit 3 consistent with the 2013 Stipulation. The Georgia PSC recognized that the certified cost and the 2013 Stipulation do not constitute a cost recovery cap. In accordance with the Georgia Integrated Resource Planning Act, any costs incurred by Georgia Power in excess of the certified amount will be included in rate base, provided Georgia Power shows the costs to be reasonable and prudent. Financing costs up to the certified amount will be collected through the NCCR tariff until the units are placed in service, while financing costs on any construction-related costs in excess of the $4.4 billion certified amount are expected to be recovered through AFUDC.

Processes are in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, 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 issues are expected to 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.

As construction continues, the risk remains that ongoing challenges with Contractor performance including additional challenges in its fabrication, assembly, delivery, and installation of the shield building and structural modules, delays in the receipt of the remaining permits necessary for the operation of Plant Vogtle Units 3 and 4, or other issues could arise and may further impact project schedule and cost. In addition, the IRS allocated production tax credits to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021.

Additional claims by the Contractor or Georgia Power (on behalf of the Vogtle Owners) are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement, but also may be resolved through litigation.

See RISK FACTORS of Georgia Power in Item 1A of the Form 10-K for a discussion of certain risks associated with the licensing, construction, and operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world.

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

Other Matters

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

The ultimate outcome of such pending or potential litigation against Georgia Power cannot be predicted at this time; however, for current proceedings not specifically reported in Note (B) to the Condensed Financial Statements herein or in Note 3 to the financial statements of Georgia Power in Item 8 of the Form 10-K, management does not

anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Georgia Power's financial statements. See Note (B) to the Condensed Financial Statements herein for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Georgia Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Georgia Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Georgia Power's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Georgia Power in Item 7 of the Form 10-K for a complete discussion of Georgia Power's critical accounting policies and estimates related to Electric Utility Regulation, Contingent Obligations, and Pension and Other Postretirement Benefits.

Asset Retirement Obligations

AROs are computed as the fair value of the 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 Georgia Power's nuclear facilities, which include Georgia Power's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2, and facilities that are subject to the CCR Rule, primarily ash ponds. In addition, Georgia Power has retirement obligations related to various landfill sites, underground storage tanks, and asbestos removal. Georgia Power 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 Georgia Power'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.

On April 17, 2015, the EPA published the final CCR Rule in the Federal Register, setting October 19, 2015 as the effective date of the CCR Rule. Georgia Power had previously recorded AROs as a result of state requirements in Georgia which closely align with the requirements of the CCR Rule. The cost estimates are based on information that was known as of June 30, 2015 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. As further analysis is performed, including evaluation of the expected timing and method of compliance and refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, Georgia Power expects to periodically update these estimates. Given the significant judgment involved in estimating AROs, Georgia Power considers the liabilities for AROs to be critical accounting estimates.

See Note 1 to the financial statements of Georgia Power under "Asset Retirement Obligations and Other Costs of Removal" and "Nuclear Decommissioning" in Item 8 of the Form 10-K and Note (A) to the Condensed Financial Statements under "Asset Retirement Obligations" herein for additional information.

Recently Issued Accounting Standards

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers*, revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. Georgia Power continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*. The ASU requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. Georgia Power currently reflects unamortized debt issuance costs in other deferred charges and assets on its balance sheet. Upon adoption, the reclassification will not have a material impact on the results of operations, financial position, or cash flows of Georgia Power.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Overview" of Georgia Power in Item 7 of the Form 10-K for additional information. Georgia Power's financial condition remained stable at June 30, 2015. Georgia Power intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit agreements to meet future capital and liquidity needs. See "Capital Requirements and Contractual Obligations," "Sources of Capital," and "Financing Activities" herein for additional information.

Net cash provided from operating activities totaled $774 million for the first six months of 2015 compared to $843 million for the corresponding period in 2014. The decrease was primarily due to lower operating revenues, partially offset by increased fuel cost recovery. Net cash used for investing activities totaled $891 million for the first six months of 2015 compared to $917 million for the corresponding period in 2014 primarily related to installation of equipment to comply with environmental standards and construction of transmission and distribution facilities. Net cash provided from financing activities totaled $117 million for the first six months of 2015 compared to $90 million in the corresponding period in 2014. The increase in cash provided from financing activities is primarily due to an increase in short-term debt borrowings. Fluctuations in cash flow from financing activities vary from period to period based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for the first six months of 2015 include increases of $468 million in property, plant, and equipment to comply with environmental standards and construction of generation, transmission, and distribution facilities and increases of $550 million and $231 million in short-term debt and long-term debt, respectively, to fund the continuous construction program and for general corporate purposes.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Georgia Power in Item 7 of the Form 10-K for a description of Georgia Power's capital requirements for its construction program, including estimated capital expenditures for Plant Vogtle Units 3 and 4 and to comply with existing environmental statutes and regulations, scheduled maturities of long-term debt, as well as related interest, derivative obligations, preferred and preference stock dividends, leases, purchase commitments, and trust funding requirements. Approximately $1.7 billion will be required through June 30, 2016 to fund maturities and announced redemptions of long-term debt. See "Sources of Capital" herein for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; 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; Georgia PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Nuclear Construction" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" herein for information regarding additional factors that may impact construction expenditures.

Sources of Capital

Except as described below with respect to the DOE loan guarantees, Georgia Power plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Georgia Power in Item 7 of the Form 10-K for additional information.

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 Eligible Project Costs incurred in connection with its construction of Plant Vogtle Units 3 and 4. Under the Loan Guarantee Agreement, the DOE agreed to guarantee borrowings of up to $3.46 billion (not to exceed 70% of Eligible Project Costs) to be made by Georgia Power under a multi-advance credit facility (FFB Credit Facility) among Georgia Power, the DOE, and the FFB. Eligible Project Costs incurred through June 30, 2015 would allow for borrowings of up to $2.2 billion under the FFB Credit Facility, of which Georgia Power has borrowed $1.8 billion. See Note 6 to the financial statements of Georgia Power under "DOE Loan Guarantee Borrowings" in Item 8 of the Form 10-K for additional information regarding the Loan Guarantee Agreement and Note (B) to the Condensed Financial Statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" herein for additional information regarding Plant Vogtle Units 3 and 4.

As of June 30, 2015, Georgia Power's current liabilities exceeded current assets by $1.3 billion primarily due to approximately $1.9 billion of long-term debt due within one year and notes payable. For the remainder of 2015, Georgia Power expects to utilize borrowings through the FFB as the primary source of long-term borrowed funds. Georgia Power also intends to utilize operating cash flows, as well as commercial paper, lines of credit, bank notes, and securities issuances, as market conditions permit, and equity contributions from Southern Company to fund its short-term capital needs. Georgia Power has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet liquidity needs.

At June 30, 2015, Georgia Power had approximately $24 million of cash and cash equivalents. Committed credit arrangements with banks at June 30, 2015 were as follows:

Expires		Total	Unused	Due Within One Year	
2016	2018			Term Out	No Term Out
(in millions)		*(in millions)*		*(in millions)*	
$ 150	$ 1,600	$ 1,750	$ 1,737	$ —	$ 150

See Note 6 to the financial statements of Georgia Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information.

A portion of the unused credit with banks is allocated to provide liquidity support to Georgia Power's variable rate pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of June 30, 2015 was approximately $970 million. In addition, at June 30, 2015, Georgia Power had $122 million of fixed rate pollution control revenue bonds outstanding that were required to be reoffered within the next 12 months.

Most of these bank credit arrangements contain covenants that limit debt levels and contain cross default provisions to other indebtedness (including guarantee obligations) of Georgia Power. Such cross default provisions to other indebtedness would trigger an event of default if Georgia Power defaulted on indebtedness or guarantee obligations over a specified threshold. Georgia Power is currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

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

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

Details of short-term borrowings were as follows:

	Short-term Debt at June 30, 2015		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)*
Commercial paper	$ 200	0.3%	$ 370	0.3%	$ 598
Short-term bank debt	—	—%	247	0.8%	250
Total	$ 200	0.3%	$ 617	0.5%	

(*) Average and maximum amounts are based upon daily balances during the three-month period ended June 30, 2015.

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

Credit Rating Risk

Georgia Power does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

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

The maximum potential collateral requirements under these contracts at June 30, 2015 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 102
Below BBB- and/or Baa3	1,341

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact Georgia Power's access to the short-term debt market and the variable rate pollution control revenue bond market.

Subsequent to June 30, 2015, S&P placed its ratings of Southern Company and the traditional operating companies (including Georgia Power) on CreditWatch with negative implications.

Financing Activities

In March 2015, Georgia Power entered into a $250 million aggregate principal amount three-month floating rate bank loan bearing interest based on one-month LIBOR. The proceeds were used for working capital and other general corporate purposes and the loan was repaid at maturity.

In April 2015, Georgia Power purchased and held $65 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Second Series 2008. Georgia Power reoffered these bonds to the public in May 2015.

In April 2015, Georgia Power redeemed $125 million aggregate principal amount of its Series Y 5.80% Senior Notes due April 15, 2035.

In May 2015, Georgia Power reoffered to the public $104.6 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2013, which had been previously purchased and held by Georgia Power since 2013.

In June 2015, Georgia Power made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $600 million. The interest rate applicable to the $600 million principal amount is 3.283% for an interest period that extends 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. Georgia Power settled $350 million of interest rate swaps related to this borrowing for approximately $6 million, which will be amortized to interest expense over 10 years.

Subsequent to June 30, 2015, $97.925 million aggregate principal amount of the Development Authority of Putnam County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Branch Project), First Series 1996, First Series 1997, Second Series 1997, and First Series 1998 were redeemed.

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

GULF POWER COMPANY

GULF POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	**2015**	2014
	(in millions)		*(in millions)*	
Operating Revenues:				
Retail revenues	**$ 327**	$ 310	**$ 620**	$ 613
Wholesale revenues, non-affiliates	**27**	34	**52**	70
Wholesale revenues, affiliates	**13**	24	**35**	76
Other revenues	**17**	16	**34**	32
Total operating revenues	**384**	384	**741**	791
Operating Expenses:				
Fuel	**122**	145	**232**	314
Purchased power, non-affiliates	**25**	14	**50**	30
Purchased power, affiliates	**9**	9	**17**	16
Other operations and maintenance	**91**	82	**185**	164
Depreciation and amortization	**40**	39	**60**	71
Taxes other than income taxes	**28**	26	**56**	53
Total operating expenses	**315**	315	**600**	648
Operating Income	**69**	69	**141**	143
Other Income and (Expense):				
Allowance for equity funds used during construction	**3**	3	**8**	5
Interest expense, net of amounts capitalized	**(12)**	(13)	**(26)**	(27)
Other income (expense), net	**(1)**	(1)	**(2)**	(1)
Total other income and (expense)	**(10)**	(11)	**(20)**	(23)
Earnings Before Income Taxes	**59**	58	**121**	120
Income taxes	**21**	22	**44**	45
Net Income	**38**	36	**77**	75
Dividends on Preference Stock	**3**	2	**5**	4
Net Income After Dividends on Preference Stock	**$ 35**	$ 34	**$ 72**	$ 71

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	**2015**	2014
	(in millions)		*(in millions)*	
Net Income	**$ 38**	$ 36	**$ 77**	$ 75
Other comprehensive income (loss)	**—**	—	**—**	—
Comprehensive Income	**$ 38**	$ 36	**$ 77**	$ 75

The accompanying notes as they relate to Gulf Power are an integral part of these condensed financial statements.

GULF POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Six Months Ended June 30,	
	2015	2014
	(in millions)	
Operating Activities:		
Net income	**$ 77**	$ 75
Adjustments to reconcile net income to net cash provided from operating activities —		
Depreciation and amortization, total	**64**	75
Deferred income taxes	**40**	20
Allowance for equity funds used during construction	**(8)**	(5)
Other, net	**11**	1
Changes in certain current assets and liabilities —		
-Receivables	**(15)**	(57)
-Fossil fuel stock	**6**	39
-Prepaid income taxes	**12**	9
-Other current assets	**1**	2
-Accounts payable	**(9)**	1
-Accrued taxes	**15**	12
-Accrued compensation	**(10)**	—
-Over recovered regulatory clause revenues	**—**	9
-Other current liabilities	**(1)**	(4)
Net cash provided from operating activities	**183**	177
Investing Activities:		
Property additions	**(148)**	(159)
Cost of removal, net of salvage	**(7)**	(6)
Other investing activities	**(19)**	(5)
Net cash used for investing activities	**(174)**	(170)
Financing Activities:		
Increase in notes payable, net	**4**	3
Proceeds —		
Common stock issued to parent	**20**	50
Pollution control revenue bonds	**—**	42
Short-term borrowings	**40**	—
Redemptions — Pollution control revenue bonds	**—**	(29)
Payment of preference stock dividends	**(5)**	(5)
Payment of common stock dividends	**(65)**	(62)
Other financing activities	**2**	2
Net cash provided from (used for) financing activities	**(4)**	1
Net Change in Cash and Cash Equivalents	**5**	8
Cash and Cash Equivalents at Beginning of Period	**39**	22
Cash and Cash Equivalents at End of Period	**$ 44**	$ 30
Supplemental Cash Flow Information:		
Cash paid (received) during the period for —		
Interest (net of $3 and $2 capitalized for 2015 and 2014, respectively)	**$ 26**	$ 26
Income taxes, net	**(9)**	17
Noncash transactions — Accrued property additions at end of period	**28**	31

The accompanying notes as they relate to Gulf Power are an integral part of these condensed financial statements.

GULF POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Assets	At June 30, 2015	At December 31, 2014
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 44**	$ 39
Receivables —		
Customer accounts receivable	**93**	73
Unbilled revenues	**77**	58
Under recovered regulatory clause revenues	**38**	57
Other accounts and notes receivable	**9**	8
Affiliated companies	**4**	10
Accumulated provision for uncollectible accounts	**(2)**	(2)
Fossil fuel stock, at average cost	**95**	101
Materials and supplies, at average cost	**55**	56
Other regulatory assets, current	**72**	74
Prepaid expenses	**35**	40
Other current assets	**3**	2
Total current assets	**523**	516
Property, Plant, and Equipment:		
In service	**4,600**	4,495
Less accumulated provision for depreciation	**1,234**	1,296
Plant in service, net of depreciation	**3,366**	3,199
Other utility plant, net	**77**	—
Construction work in progress	**387**	465
Total property, plant, and equipment	**3,830**	3,664
Other Property and Investments	**15**	15
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**59**	56
Other regulatory assets, deferred	**406**	416
Other deferred charges and assets	**41**	41
Total deferred charges and other assets	**506**	513
Total Assets	**$ 4,874**	$ 4,708

The accompanying notes as they relate to Gulf Power are an integral part of these condensed financial statements.

GULF POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	**At June 30, 2015**	At December 31, 2014
	(in millions)	
Current Liabilities:		
Notes payable	**$ 154**	$ 110
Accounts payable —		
Affiliated	**72**	87
Other	**52**	56
Customer deposits	**36**	35
Other accrued taxes	**24**	9
Accrued interest	**10**	11
Accrued compensation	**13**	23
Deferred capacity expense, current	**22**	22
Liabilities from risk management activities	**32**	37
Other current liabilities	**21**	23
Total current liabilities	**436**	413
Long-term Debt	**1,370**	1,370
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**852**	800
Employee benefit obligations	**119**	121
Other cost of removal obligations	**222**	235
Other regulatory liabilities, deferred	**49**	49
Deferred capacity expense	**152**	163
Other deferred credits and liabilities	**187**	101
Total deferred credits and other liabilities	**1,581**	1,469
Total Liabilities	**3,387**	3,252
Preference Stock	**147**	147
Common Stockholder's Equity:		
Common stock, without par value —		
Authorized — 20,000,000 shares		
Outstanding — June 30, 2015: 5,642,717 shares		
— December 31, 2014: 5,442,717 shares	**503**	483
Paid-in capital	**564**	560
Retained earnings	**274**	267
Accumulated other comprehensive loss	**(1)**	(1)
Total common stockholder's equity	**1,340**	1,309
Total Liabilities and Stockholder's Equity	**$ 4,874**	$ 4,708

The accompanying notes as they relate to Gulf Power are an integral part of these condensed financial statements.

OVERVIEW

Gulf Power operates as a vertically integrated utility providing electricity to retail customers within its traditional service territory located in northwest Florida and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of Gulf Power's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, restoration following major storms, and fuel. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge Gulf Power for the foreseeable future. Capacity revenues represent the majority of Gulf Power's wholesale earnings. Gulf Power currently has long-term sales agreements for 100% of Gulf Power's co-ownership of Plant Scherer Unit 3 (205 MWs) through 2015 and 41% through 2019. These capacity revenues represented 82% of total wholesale capacity revenues for 2014. Gulf Power is actively evaluating strategic alternatives related to this asset, including replacement wholesale contracts, but the expiration of current contracts could have a material negative impact on Gulf Power's earnings.

Gulf Power continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preference stock. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Key Performance Indicators" of Gulf Power in Item 7 of the Form 10-K.

RESULTS OF OPERATIONS

Net Income

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$1	2.9	$1	1.4

Gulf Power's net income after dividends on preference stock for the second quarter 2015 was $35 million compared to $34 million for the corresponding period in 2014. The increase was primarily due to higher retail revenues related to a base rate increase, partially offset by higher operations and maintenance expenses.

Gulf Power's net income after dividends on preference stock for year-to-date 2015 was $72 million compared to $71 million for the corresponding period in 2014. The increase was primarily due to a reduction in depreciation, as authorized by the Florida PSC, and higher retail revenues related to a base rate increase, partially offset by higher operations and maintenance expenses.

Retail Revenues

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$17	5.5	$7	1.1

In the second quarter 2015, retail revenues were $327 million compared to $310 million for the corresponding period in 2014. For year-to-date 2015, retail revenues were $620 million compared to $613 million for the corresponding period in 2014.

Details of the changes in retail revenues were as follows:

	Second Quarter 2015		Year-to-Date 2015	
	(in millions)	*(% change)*	*(in millions)*	*(% change)*
Retail – prior year	$ 310		$ 613	
Estimated change resulting from –				
Rates and pricing	7	2.3	10	1.7
Sales growth	2	0.6	—	—
Weather	4	1.3	4	0.6
Fuel and other cost recovery	4	1.3	(7)	(1.2)
Retail – current year	$ 327	5.5%	$ 620	1.1%

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters" of Gulf Power in Item 7 and Note 1 to the financial statements of Gulf Power under "Revenues" and Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters" in Item 8 of the Form 10-K for additional information regarding Gulf Power's retail base rate case and cost recovery clauses, including Gulf Power's fuel cost recovery, purchased power capacity recovery, environmental cost recovery, and energy conservation cost recovery clauses.

Revenues associated with changes in rates and pricing increased in the second quarter and year-to-date 2015 when compared to the corresponding periods in 2014 primarily due to an increase in retail base rates effective in January 2015, as authorized in a settlement agreement for Gulf Power's 2013 base rate case, and higher revenues associated with an increase in the environmental and energy conservation cost recovery clause rates effective in January 2015.

Revenues attributable to changes in sales increased in the second quarter 2015 when compared to the corresponding period in 2014. Weather-adjusted KWH energy sales to residential and commercial customers increased 3.0% and 1.6%, respectively, due to customer growth and higher customer usage. KWH energy sales to industrial customers decreased 2.8% primarily due to increased customer co-generation.

Revenues attributable to changes in sales remained essentially flat year-to-date 2015 when compared to the corresponding period in 2014. Weather-adjusted KWH energy sales to residential and commercial customers decreased 0.9% and 0.1%, respectively, due to lower customer usage, partially offset by customer growth. KWH energy sales to industrial customers decreased 2.7% primarily due to increased customer co-generation.

Fuel and other cost recovery revenues increased in the second quarter 2015 when compared to the corresponding period in 2014 primarily due to higher revenues associated with increased recoverable purchased power capacity costs, partially offset by lower revenues associated with fuel costs as the result of decreased generation and lower purchased power energy costs. For year-to-date 2015, fuel and other cost recovery revenues decreased when compared to the corresponding period in 2014 primarily due to lower revenues associated with fuel costs as a result of decreased generation and lower purchased power energy costs, partially offset by higher revenues associated with purchased power capacity costs.

Fuel and other cost recovery provisions include fuel expenses, the energy component of purchased power costs, purchased power capacity costs, and the difference between projected and actual costs and revenues related to energy conservation and environmental compliance. See Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Cost Recovery Clauses – Retail Fuel Cost Recovery" in Item 8 of the Form 10-K for additional information.

Wholesale Revenues – Non-Affiliates

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(7)	(20.6)	$(18)	(25.7)

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 wholesale earnings. Energy is generally sold at variable cost and does not have a significant impact on wholesale earnings. Short-term opportunity sales are made at market-based rates that generally provide a margin above Gulf Power'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 Gulf Power's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

In the second quarter 2015, wholesale revenues from sales to non-affiliates were $27 million compared to $34 million for the corresponding period in 2014. The decrease was primarily due to a 43.5% 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 customer-owned generation.

For year-to-date 2015, wholesale revenues from sales to non-affiliates were $52 million compared to $70 million for the corresponding period in 2014. The decrease was primarily due to a 52.1% 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 customer-owned generation.

Wholesale Revenues – Affiliates

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(11)	(45.8)	$(41)	(53.9)

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the IIC, as approved by the FERC. These transactions do not have a significant impact on earnings since the revenue related to these energy sales generally offsets the cost of energy sold.

In the second quarter 2015, wholesale revenues from sales to affiliates were $13 million compared to $24 million for the corresponding period in 2014. The decrease was primarily due to a 29.9% decrease in KWH sales that resulted from planned outages for Gulf Power generation resources and a 20.6% decrease in the price of energy sold to affiliates due to lower power pool interchange rates resulting from lower natural gas prices.

For year-to-date 2015, wholesale revenues from sales to affiliates were $35 million compared to $76 million for the corresponding period in 2014. The decrease was primarily due to a 37.2% decrease in KWH sales that resulted from planned outages for Gulf Power generation resources and a 26.1% decrease in the price of energy sold to affiliates due to lower power pool interchange rates resulting from lower natural gas prices.

Fuel and Purchased Power Expenses

	Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
	(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
Fuel	$ (23)	(15.9)	$ (82)	(26.1)
Purchased power – non-affiliates	11	78.6	20	66.7
Purchased power – affiliates	—	—	1	6.3
Total fuel and purchased power expenses	$ (12)		$ (61)	

In the second quarter 2015, total fuel and purchased power expenses were $156 million compared to $168 million for the corresponding period in 2014. The decrease was primarily the result of a $9 million decrease in the volume of KWHs generated and purchased due to planned outages for Gulf Power's generation and a resource contracted under a PPA and a $3 million net decrease due to the lower average cost of fuel and purchased power.

For year-to-date 2015, total fuel and purchased power expenses were $299 million compared to $360 million for the corresponding period in 2014. The decrease was primarily the result of a $50 million decrease in the volume of KWHs generated and purchased due to planned outages for Gulf Power's generation and a resource contracted under a PPA and an $11 million net decrease due to the 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 Gulf Power's fuel cost and purchased power capacity recovery clauses. See Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Cost Recovery Clauses – Retail Fuel Cost Recovery" and " – Purchased Power Capacity Recovery" in Item 8 of the Form 10-K for additional information.

Details of Gulf Power's generation and purchased power were as follows:

	Second Quarter 2015	Second Quarter 2014	**Year-to-Date 2015**	Year-to-Date 2014
Total generation *(millions of KWHs)*	**2,360**	2,670	**4,596**	5,632
Total purchased power *(millions of KWHs)*	**1,336**	1,281	**2,594**	2,711
Sources of generation *(percent)* –				
Coal	**61**	69	**60**	70
Gas	**39**	31	**40**	30
Cost of fuel, generated *(cents per net KWH)* –				
Coal	**4.05**	4.09	**4.02**	4.21
Gas	**4.38**	3.99	**4.17**	3.82
Average cost of fuel, generated *(cents per net KWH)*	**4.18**	4.06	**4.08**	4.09
Average cost of purchased power *(cents per net KWH)*(*)	**4.25**	4.71	**4.31**	4.75

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

Fuel

In the second quarter 2015, fuel expense was $122 million compared to $145 million for the corresponding period in 2014. The decrease was primarily due to an 11.6% decrease in the volume of KWHs generated due to planned outages for Gulf Power's generation and a resource contracted under a PPA. This was partially offset by a 3.0% increase in the average cost of fuel due to higher natural gas prices per KWH generated, which includes firm gas transportation and storage.

For year-to-date 2015, fuel expense was $232 million compared to $314 million for the corresponding period in 2014. The decrease was primarily due to an 18.4% decrease in the volume of KWHs generated due to planned outages for Gulf Power's generation and a resource contracted under a PPA.

Purchased Power – Non-Affiliates

In the second quarter 2015, purchased power expense from non-affiliates was $25 million compared to $14 million for the corresponding period in 2014. The increase was primarily due to a $10 million increase in capacity costs associated with a scheduled rate increase for an existing PPA, partially offset by the expiration of another PPA in mid-2014. The increase was partially offset by a 7.9% decrease in the volume of KWHs purchased due to a planned outage for a resource contracted under a PPA.

For year-to-date 2015, purchased power expense from non-affiliates was $50 million compared to $30 million for the corresponding period in 2014. The increase was primarily due to a $26 million increase in capacity costs associated with a scheduled rate increase for an existing PPA, partially offset by the expiration of another PPA in mid-2014. The increase was partially offset by a 17.4% decrease in the volume of KWHs purchased due to a planned outage for a resource contracted under a PPA.

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

Purchased Power – Affiliates

In the second quarter 2015 and the corresponding period in 2014, purchased power expense from affiliates was $9 million. The volume of KWHs purchased increased 55.4% due to planned outages for Gulf Power's generation and a resource contracted under a PPA. The increase was offset by a 39.1% decrease in the average cost per KWH purchased due to lower power pool interchange rates.

For year-to-date 2015, purchased power expense from affiliates was $17 million compared to $16 million for the corresponding period in 2014. The increase was primarily due to a 68.5% increase in the volume of KWHs purchased due to planned outages for Gulf Power's generation and a resource contracted under a PPA, largely offset by a 36.0% 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

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$9	11.0	$21	12.8

In the second quarter 2015, other operations and maintenance expenses were $91 million compared to $82 million for the corresponding period in 2014. The increase was primarily due to increases of $6 million in routine and planned maintenance expenses at generation and distribution facilities, $1 million in energy services expenses, $1 million in customer service expenses, and $1 million in employee benefits including pension costs.

For year-to-date 2015, other operations and maintenance expenses were $185 million compared to $164 million for the corresponding period in 2014. The increase was primarily due to increases of $11 million in routine and planned maintenance expenses at generation facilities, $2 million in energy services expenses, $2 million in customer service expenses, and $2 million in employee benefits including pension costs.

Expenses from energy services did not have a significant impact on earnings since they were generally offset by associated revenues. See Note (F) to the Condensed Financial Statements herein for additional information related to pension costs.

Depreciation and Amortization

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$1	2.6	$(11)	(15.5)

In the second quarter 2015, depreciation and amortization was $40 million compared to $39 million for the corresponding period in 2014. The increase in depreciation and amortization was primarily attributable to property additions at generation, transmission, and distribution facilities.

For year-to-date 2015, depreciation and amortization was $60 million compared to $71 million for the corresponding period in 2014. As authorized by the Florida PSC in a settlement agreement, Gulf Power recorded a $19.6 million reduction in depreciation in the first half of 2015 as compared to $5.4 million in the corresponding period in 2014. The decrease was partially offset by increases of $3 million primarily attributable to property additions at generation, transmission, and distribution facilities.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Retail Base Rate Case" of Gulf Power in Item 7 and Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Retail Base Rate Case" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under "Retail Regulatory Matters – Gulf Power – Retail Base Rate Case" herein for additional information.

Taxes Other Than Income Taxes

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$2	7.7	$3	5.7

In the second quarter 2015, taxes other than income taxes were $28 million compared to $26 million for the corresponding period in 2014. For year-to-date 2015, taxes other than income taxes were $56 million compared to $53 million for the corresponding period in 2014. The increases were primarily due to increases in property taxes, franchise fees, and gross receipts taxes. Franchise fees and gross receipts taxes have no impact on net income.

Allowance for Equity Funds Used During Construction

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$—	—	$3	60.0

For year-to-date 2015, AFUDC equity was $8 million compared to $5 million for the corresponding period in 2014. The increase was primarily due to increased construction related to environmental control projects at generation facilities.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Gulf Power's future earnings potential. The level of Gulf Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Gulf Power's business of selling electricity. These factors include Gulf Power's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining and

growing sales which are subject to a number of factors. These factors include weather, competition, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, the rate of economic growth or decline in Gulf Power's service territory, and the successful remarketing of wholesale capacity as current contracts expire. Changes in regional and global economic conditions may impact sales for Gulf Power as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Gulf Power in Item 7 of the Form 10-K.

Gulf Power's wholesale business consists of two types of agreements. The first type, referred to as requirements service, provides that Gulf Power serves the customer's capacity and energy requirements from Gulf Power resources. The second type, referred to as a unit sale, is a wholesale customer purchase from a dedicated generating plant unit where a portion of that unit is reserved for the customer. These agreements are associated with Gulf Power's co-ownership of Plant Scherer Unit 3 (205 MWs) and consist of both capacity and energy sales. Capacity revenues represent the majority of Gulf Power's wholesale earnings. Gulf Power currently has long-term sales agreements for 100% of Gulf Power's co-ownership of that unit through 2015 and 41% through 2019. These capacity revenues represented 82% of total wholesale capacity revenues for 2014. Gulf Power is actively evaluating strategic alternatives related to this asset, including replacement wholesale contracts, but the expiration of current contracts could have a material negative impact on Gulf Power's earnings. In the event some portion of Gulf Power's ownership in Plant Scherer is not subject to a replacement long-term wholesale contract, the proportionate amount of the unit may be sold into the power pool or into the wholesale market.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in retail rates or through long-term wholesale agreements on a timely basis or through market-based contracts. The State of Florida has statutory provisions that allow a utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Gulf Power's current long-term wholesale agreements contain provisions that permit charging the customer with costs incurred as a result of changes in environmental laws and regulations. The full impact of any such regulatory or legislative changes cannot be determined at this time. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates or long-term wholesale agreements could contribute to reduced demand for electricity as well as impact the cost competitiveness of wholesale capacity, which could negatively affect results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" and "Retail Regulatory Matters – Cost Recovery Clauses – Environmental Cost Recovery" of Gulf Power in Item 7 and Note 3 to the financial statements of Gulf Power under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

Environmental Statutes and Regulations

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Gulf Power in Item 7 of the Form 10-K for additional information regarding the EPA's proposed regulations governing emissions during startup, shutdown, or malfunction (SSM), the final MATS rule, and the Cross State Air Pollution Rule (CSAPR).

On June 12, 2015, the EPA published a final rule requiring affected states (including Florida, Georgia, and Mississippi) to revise or remove state implementation plan (SIP) provisions regarding excess emissions that occur during periods of SSM by no later than November 22, 2016. The ultimate impact of the final rule will depend on the

outcome of any legal challenges and the development and approval of SIPs by the affected states and cannot be determined at this time.

On June 29, 2015, the U.S. Supreme Court issued a decision finding that the EPA had failed to properly consider costs in its decision to regulate hazardous air pollutant emissions from electric generating units under the MATS rule and remanded the case to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The MATS rule remains in effect while the U.S. Court of Appeals for the District of Columbia Circuit and the EPA respond to the decision. The ultimate impact of this decision cannot be determined at this time.

On July 28, 2015, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion invalidating certain emissions budgets under the CSAPR Phase II emissions trading program for a number of states, including Florida and Georgia. The court's decision leaves the emissions trading program in place and remands the rule to the EPA for further action consistent with the court's decision. The court rejected all other pending challenges to the rule. The ultimate impact of this decision will depend on additional rulemaking and cannot be determined at this time.

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Gulf Power in Item 7 of the Form 10-K for additional information regarding the EPA's and the U.S. Army Corps of Engineers' proposed rule revising the definition of waters of the U.S. under the Clean Water Act (CWA).

On June 29, 2015, the EPA and the U.S. Army Corps of Engineers jointly published a final rule revising the regulatory definition of waters of the U.S. for all 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 becomes effective August 28, 2015. The ultimate impact of the final rule will depend on the outcome of any legal challenges and the EPA's and the U.S. Army Corps of Engineers' field-level implementation of the rule and cannot be determined at this time.

Coal Combustion Residuals

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Coal Combustion Residuals" of Gulf Power in Item 7 of the Form 10-K for additional information regarding the EPA's regulation of CCR.

On April 17, 2015, the EPA published the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule) in the Federal Register, setting October 19, 2015 as the effective date of the CCR Rule. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on Gulf Power's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. Based on initial estimates, Gulf Power recorded incremental asset retirement obligations (ARO) of approximately $75 million related to the CCR Rule in the second quarter 2015. As further analysis is performed, including evaluation of the expected timing and method of compliance and refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, Gulf Power expects to periodically update these estimates.

In connection with a proposed settlement related to the closure of Plant Scholz, Gulf Power may incur additional AROs associated with CCR of approximately $15 million to $35 million.

See Note (A) to the Condensed Financial Statements herein for additional information regarding Gulf Power's AROs.

Global Climate Issues

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" of Gulf Power in Item 7 of the Form 10-K for additional information regarding the EPA's proposed regulation of CO_2 from fossil-fuel-fired electric generating units.

On August 3, 2015, the EPA released pre-publication versions of two final rules that would limit CO_2 emissions from fossil fuel-fired electric generating units. One of the final rules contains specific emission standards governing CO_2 emissions from new, modified, and reconstructed units. The other final rule 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. At the same time, the EPA also proposed a federal plan and proposed model rule that states can adopt or that would be put in place if, in response to the final guidelines, a state either does not submit a state plan or its plan is not approved by the EPA. 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. Gulf Power's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through market-based contracts. However, the ultimate financial and operational impact of the final rules on Gulf Power cannot be determined at this time and will depend on numerous factors including the Southern Company system's ongoing review of the final rules; the outcome of any 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; the impact of future changes in generation and emissions related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

FERC Matters

Gulf Power has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional operating companies (including Gulf Power) and Southern Power filed a triennial market power analysis on June 30, 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional operating companies' (including Gulf Power's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional operating companies and in some adjacent areas. To retain market-based rate authority, the FERC directed the traditional operating companies (including Gulf Power) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional operating companies (including Gulf Power) and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

Gulf Power's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. Gulf Power's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through base rates. See Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Retail Base Rate Case" in Item 8 of the Form 10-K for additional information.

Retail Base Rate Case

In December 2013, the Florida PSC approved a settlement agreement that provides Gulf Power may reduce depreciation expense and record a regulatory asset up to $62.5 million between January 2014 and June 2017. In any given month, such depreciation expense reduction may not exceed the amount necessary for the ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized retail ROE range then in effect. Gulf Power recognized a $19.6 million reduction in depreciation expense in the first six months of 2015.

Cost Recovery Clauses

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Cost Recovery Clauses" of Gulf Power in Item 7 and Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Cost Recovery Clauses" in Item 8 of the Form 10-K for additional information regarding Gulf Power's recovery of retail costs through various regulatory clauses and accounting orders. Gulf Power has four regulatory clauses which are approved by the Florida PSC. See Note (B) to the Condensed Financial Statements herein for additional information.

Renewables

On April 16, 2015, the Florida PSC approved three energy purchase agreements totaling 120 MWs of utility-scale solar generation located at three military installations in northwest Florida. On May 5, 2015, the Florida PSC approved an energy purchase agreement for up to 178 MWs of wind generation in central Oklahoma. Purchases under these agreements will be for energy only and will be recovered through Gulf Power's fuel cost recovery mechanism.

Other Matters

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

The ultimate outcome of such pending or potential litigation against Gulf Power cannot be predicted at this time; however, for current proceedings not specifically reported in Note (B) to the Condensed Financial Statements herein or in Note 3 to the financial statements of Gulf Power in Item 8 of the Form 10-K, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Gulf Power's financial statements. See Note (B) to the Condensed Financial Statements herein for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Gulf Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Gulf Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Gulf Power's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Gulf Power in Item 7 of the Form 10-K for a complete discussion of Gulf Power's critical accounting policies and estimates related to Electric Utility Regulation, Contingent Obligations, and Pension and Other Postretirement Benefits.

Asset Retirement Obligations

AROs are computed as the fair value of the 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 Gulf Power's combustion turbines at its Pea Ridge facility and facilities that are subject to the CCR Rule, primarily ash ponds. In addition, Gulf Power has retirement obligations related to various landfill sites, a barge unloading dock, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. Gulf Power 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.

On April 17, 2015, the EPA published the final CCR Rule in the Federal Register, setting October 19, 2015 as the effective date of the CCR Rule. Therefore, Gulf Power recorded new AROs for facilities that are subject to the CCR Rule. The cost estimates are based on information that was known as of June 30, 2015 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. As further analysis is performed, including evaluation of the expected timing and method of compliance and refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, Gulf Power expects to periodically update these estimates. Given the significant judgment involved in estimating AROs, Gulf Power considers the liabilities for AROs to be critical accounting estimates.

See Note 1 to the financial statements of Gulf Power under "Asset Retirement Obligations and Other Costs of Removal" in Item 8 of the Form 10-K and Note (A) to the Condensed Financial Statements under "Asset Retirement Obligations" herein for additional information.

Recently Issued Accounting Standards

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers*, revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. Gulf Power continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*. The ASU requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. Gulf Power currently reflects unamortized debt issuance costs in other deferred charges and assets on its balance sheet. Upon adoption, the reclassification will not have a material impact on the results of operations, financial position, or cash flows of Gulf Power.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Overview" of Gulf Power in Item 7 of the Form 10-K for additional information. Gulf Power's financial condition remained stable at June 30, 2015. Gulf Power intends to continue to monitor its access to short-term and long-term

capital markets as well as bank credit agreements to meet future capital and liquidity needs. See "Capital Requirements and Contractual Obligations," "Sources of Capital," and "Financing Activities" herein for additional information.

Net cash provided from operating activities totaled $183 million for the first six months of 2015 compared to $177 million for the corresponding period in 2014. The $6 million increase in net cash was primarily due to increases in cash flows related to cost recovery clauses and an increase in deferred income taxes related to bonus depreciation, partially offset by decreases in the timing of fossil fuel stock purchases, accrued compensation, and accounts payable. Net cash used for investing activities totaled $174 million in the first six months of 2015 primarily due to property additions to utility plant. Net cash used for financing activities totaled $4 million for the first six months of 2015 primarily due to the payment of common stock dividends, partially offset by an increase in notes payable and the issuance of common stock to Southern Company. Fluctuations in cash flow from financing activities vary from period to period based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for the first six months of 2015 include increases of $166 million in net property, plant, and equipment, $86 million in other deferred credits and other liabilities primarily related to AROs associated with the CCR Rule, $52 million in accumulated deferred income tax liabilities primarily related to bonus depreciation, and $44 million in notes payable.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Gulf Power in Item 7 of the Form 10-K for a description of Gulf Power's capital requirements for its construction program, including estimated capital expenditures to comply with existing environmental statutes and regulations, scheduled maturities of long-term debt, as well as related interest, leases, derivative obligations, preference stock dividends, purchase commitments, trust funding requirements, and unrecognized tax benefits. Approximately $60 million will be required through June 30, 2016 to fund announced redemptions of long-term debt. See "Financing Activities" herein for additional information.

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

Sources of Capital

Gulf Power plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Gulf Power in Item 7 of the Form 10-K for additional information.

Gulf Power's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business. Gulf Power has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet short-term liquidity needs, including its commercial paper program which is supported by bank credit facilities.

At June 30, 2015, Gulf Power had approximately $44 million of cash and cash equivalents. Committed credit arrangements with banks at June 30, 2015 were as follows:

Expires			Total	Unused	Executable Term Loans		Due Within One Year	
2015	2016	2017			One Year	Two Years	Term Out	No Term Out
(in millions)			(in millions)		(in millions)		(in millions)	
$ 20	$ 225	$ 30	$ 275	$ 275	$ 50	$ —	$ 50	$ 195

See Note 6 to the financial statements of Gulf Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information.

Most of the unused credit arrangements with banks is allocated to provide liquidity support to Gulf Power's variable rate pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of June 30, 2015 was approximately $69 million. In addition, at June 30, 2015, Gulf Power had approximately $46 million of fixed rate pollution control revenue bonds outstanding that were required to be reoffered within the next 12 months.

Most of these bank credit arrangements contain covenants that limit debt levels and contain cross default provisions to other indebtedness (including guarantee obligations) that are restricted only to the indebtedness of Gulf Power. Such cross default provisions to other indebtedness would trigger an event of default if Gulf Power defaulted on indebtedness or guarantee obligations over a specified threshold. Gulf Power is currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

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

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

Details of short-term borrowings were as follows:

	Short-term Debt at June 30, 2015		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)
Commercial paper	$ 114	0.3%	$ 133	0.3%	$ 175
Short-term bank debt	40	1.3%	10	1.3%	40
Total	$ 154	0.6%	$ 143	0.4%	

(*) Average and maximum amounts are based upon daily balances during the three-month period ended June 30, 2015.

Gulf Power believes the need for working capital can be adequately met by utilizing the commercial paper program, lines of credit, and operating cash flows.

Credit Rating Risk

Gulf Power does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

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

The maximum potential collateral requirements under these contracts at June 30, 2015 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 91
Below BBB- and/or Baa3	481

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact Gulf Power's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

Subsequent to June 30, 2015, S&P placed its ratings of Southern Company and the traditional operating companies (including Gulf Power) on CreditWatch with negative implications.

Market Price Risk

Gulf Power's market risk exposure relative to interest rate changes for the second quarter and year-to-date 2015 has not changed materially compared to the December 31, 2014 reporting period. Gulf Power's exposure to market volatility in commodity fuel prices and prices of electricity with respect to its wholesale generating capacity is limited because its long-term sales agreements shift substantially all fuel cost responsibility to the purchaser. However, Gulf Power could become exposed to market volatility in energy-related commodity prices to the extent any wholesale generating capacity is uncontracted. Gulf Power currently has long-term sales agreements for 100% of its wholesale capacity through 2015 and 41% through 2019. These capacity revenues represented 82% of total wholesale capacity revenues for 2014. Gulf Power is actively pursuing replacement wholesale contracts but the expiration of current contracts could have a material negative impact on Gulf Power's earnings. In the event some portion of Gulf Power's ownership in Plant Scherer is not subject to a replacement long-term wholesale contract, the proportionate amount of the unit may be sold into the power pool or into the wholesale market. For an in-depth discussion of Gulf Power's market risks, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of Gulf Power in Item 7 of the Form 10-K.

Financing Activities

In January 2015, Gulf Power 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 Gulf Power's short-term debt and for other general corporate purposes, including Gulf Power's continuous construction program.

In June 2015, Gulf Power entered into a three-month floating rate bank loan bearing interest based on one-month LIBOR. This short-term loan was for $40 million aggregate principal amount and the proceeds were used for credit support, working capital, and other general corporate purposes.

Subsequent to June 30, 2015, Gulf Power purchased and held $13 million aggregate principal amount of Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds (Gulf Power Company Project), Series 2012. Gulf Power reoffered these bonds on July 16, 2015.

Subsequent to June 30, 2015, Gulf Power announced the redemption in September 2015 of $60 million aggregate principal amount of its Series L 5.65% Senior Notes due September 1, 2035.

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

MISSISSIPPI POWER COMPANY

MISSISSIPPI POWER COMPANY
CONDENSED STATEMENTS OF OPERATIONS (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	**2015**	2014
	(in millions)		*(in millions)*	
Operating Revenues:				
Retail revenues	**$ 189**	$ 211	**$ 357**	$ 418
Wholesale revenues, non-affiliates	**63**	75	**141**	172
Wholesale revenues, affiliates	**18**	20	**45**	43
Other revenues	**5**	5	**9**	9
Total operating revenues	**275**	311	**552**	642
Operating Expenses:				
Fuel	**115**	143	**229**	290
Purchased power, non-affiliates	**2**	1	**3**	13
Purchased power, affiliates	**2**	6	**4**	15
Other operations and maintenance	**68**	61	**144**	125
Depreciation and amortization	**30**	24	**57**	47
Taxes other than income taxes	**23**	20	**48**	41
Estimated loss on Kemper IGCC	**23**	—	**32**	380
Total operating expenses	**263**	255	**517**	911
Operating Income (Loss)	**12**	56	**35**	(269)
Other Income and (Expense):				
Allowance for equity funds used during construction	**25**	37	**53**	75
Interest expense, net of amounts capitalized	**30**	(13)	**19**	(25)
Other income (expense), net	**(1)**	(1)	**(2)**	(4)
Total other income and (expense)	**54**	23	**70**	46
Earnings (Loss) Before Income Taxes	**66**	79	**105**	(223)
Income taxes (benefit)	**16**	16	**20**	(114)
Net Income (Loss)	**50**	63	**85**	(109)
Dividends on Preferred Stock	**1**	1	**1**	1
Net Income (Loss) After Dividends on Preferred Stock	**$ 49**	$ 62	**$ 84**	$ (110)

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	**2015**	2014
	(in millions)		*(in millions)*	
Net Income (Loss)	**$ 50**	$ 63	**$ 85**	$ (109)
Other comprehensive income (loss)	**—**	—	**—**	—
Comprehensive Income (Loss)	**$ 50**	$ 63	**$ 85**	$ (109)

The accompanying notes as they relate to Mississippi Power are an integral part of these condensed financial statements.

MISSISSIPPI POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Six Months Ended June 30, 2015	2014
	(in millions)	
Operating Activities:		
Net income (loss)	$ 85	$ (109)
Adjustments to reconcile net income (loss) to net cash provided from operating activities —		
Depreciation and amortization, total	55	50
Deferred income taxes	694	(108)
Investment tax credits	32	28
Allowance for equity funds used during construction	(53)	(75)
Regulatory assets associated with Kemper IGCC	(50)	(26)
Estimated loss on Kemper IGCC	32	380
Income taxes receivable, non-current	(544)	—
Other, net	8	7
Changes in certain current assets and liabilities —		
-Receivables	6	(32)
-Fossil fuel stock	5	32
-Prepaid income taxes	24	(12)
-Other current assets	(7)	(5)
-Accounts payable	(25)	4
-Accrued taxes	(51)	(23)
-Accrued interest	(7)	13
-Accrued compensation	(12)	4
-Over recovered regulatory clause revenues	32	(18)
-Mirror CWIP	82	67
-Other current liabilities	3	1
Net cash provided from operating activities	309	178
Investing Activities:		
Property additions	(428)	(692)
Construction payables	(15)	(28)
Other investing activities	(17)	(13)
Net cash used for investing activities	(460)	(733)
Financing Activities:		
Increase in notes payable, net	475	—
Proceeds —		
Capital contributions from parent company	77	211
Bonds — Other	—	12
Interest-bearing refundable deposit	—	75
Long-term debt issuance to parent company	—	220
Other long-term debt issuances	—	250
Short-term borrowings	30	—
Redemptions — Other long-term debt	(350)	—
Payment of preferred stock dividends	(1)	(1)
Return of capital	—	(110)
Other financing activities	(1)	(1)
Net cash provided from financing activities	230	656
Net Change in Cash and Cash Equivalents	79	101
Cash and Cash Equivalents at Beginning of Period	133	145
Cash and Cash Equivalents at End of Period	$ 212	$ 246
Supplemental Cash Flow Information:		
Cash paid (received) during the period for —		
Interest (paid $39 and $37, net of $37 and $29 capitalized for 2015 and 2014, respectively)	$ 2	$ 8
Income taxes, net	(181)	(34)
Noncash transactions —		
Accrued property additions at end of period	99	136
Issuance of promissory note to parent related to repayment of interest-bearing refundable deposits and accrued interest	301	—

The accompanying notes as they relate to Mississippi Power are an integral part of these condensed financial statements.

MISSISSIPPI POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Assets	At June 30, 2015	At December 31, 2014
	(in millions)	
Current Assets:		
Cash and cash equivalents	$ 212	$ 133
Receivables —		
Customer accounts receivable	44	43
Unbilled revenues	37	35
Other accounts and notes receivable	11	11
Affiliated companies	43	51
Accumulated provision for uncollectible accounts	(1)	(1)
Fossil fuel stock, at average cost	95	100
Materials and supplies, at average cost	69	62
Other regulatory assets, current	69	73
Prepaid income taxes	193	191
Other current assets	7	6
Total current assets	779	704
Property, Plant, and Equipment:		
In service	4,456	4,378
Less accumulated provision for depreciation	1,194	1,173
Plant in service, net of depreciation	3,262	3,205
Construction work in progress	2,543	2,161
Total property, plant, and equipment	5,805	5,366
Other Property and Investments	6	5
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	260	226
Other regulatory assets, deferred	482	385
Income taxes receivable, non-current	544	—
Other deferred charges and assets	71	71
Total deferred charges and other assets	1,357	682
Total Assets	$ 7,947	$ 6,757

The accompanying notes as they relate to Mississippi Power are an integral part of these condensed financial statements.

MISSISSIPPI POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	**At June 30, 2015**	At December 31, 2014
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 429**	$ 778
Notes payable	**505**	—
Interest-bearing refundable deposits	**—**	275
Accounts payable —		
Affiliated	**88**	86
Other	**136**	178
Accrued taxes —		
Accrued income taxes	**—**	142
Other accrued taxes	**47**	84
Accrued interest	**13**	76
Accrued compensation	**14**	26
Over recovered regulatory clause liabilities	**33**	1
Mirror CWIP	**353**	271
Other current liabilities	**59**	61
Total current liabilities	**1,677**	1,978
Long-term Debt:		
Long-term debt, affiliated	**301**	—
Long-term debt, non-affiliated	**1,623**	1,630
Total Long-term Debt	**1,924**	1,630
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**844**	285
Accumulated deferred investment tax credits	**282**	283
Employee benefit obligations	**146**	148
Asset retirement obligations	**148**	48
Other cost of removal obligations	**170**	166
Other regulatory liabilities, deferred	**65**	64
Other deferred credits and liabilities	**410**	38
Total deferred credits and other liabilities	**2,065**	1,032
Total Liabilities	**5,666**	4,640
Redeemable Preferred Stock	**33**	33
Common Stockholder's Equity:		
Common stock, without par value —		
Authorized — 1,130,000 shares		
Outstanding — 1,121,000 shares	**38**	38
Paid-in capital	**2,692**	2,612
Accumulated deficit	**(475)**	(559)
Accumulated other comprehensive loss	**(7)**	(7)
Total common stockholder's equity	**2,248**	2,084
Total Liabilities and Stockholder's Equity	**$ 7,947**	$ 6,757

The accompanying notes as they relate to Mississippi Power are an integral part of these condensed financial statements.

OVERVIEW

Mississippi Power operates as a vertically integrated utility providing electricity to retail customers within its traditional service territory located within the State of Mississippi and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of Mississippi Power's business of selling electricity. These factors include Mississippi Power's ability to maintain and grow energy sales and to operate in a constructive regulatory environment that provides timely recovery of prudently-incurred costs. These costs include those related to the completion and operation of major construction projects, primarily the Kemper IGCC and the Plant Daniel scrubber project, projected long-term demand growth, reliability, fuel, and increasingly stringent environmental standards, as well as ongoing capital expenditures required for maintenance. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge Mississippi Power for the foreseeable future.

In 2010, the Mississippi PSC issued a CPCN authorizing the acquisition, construction, and operation of the Kemper IGCC. The certificated cost estimate of the Kemper IGCC established by the Mississippi PSC was $2.4 billion with 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 (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).

Mississippi Power's current cost estimate for the Kemper IGCC in total is approximately $6.23 billion, which includes approximately $4.96 billion of costs subject to the construction cost cap. 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 DOE Grants and excluding the Cost Cap Exceptions. Mississippi Power recorded pre-tax charges to income for revisions to the cost estimate of $23 million ($14 million after tax) in the second quarter 2015 and $9 million ($6 million after tax) in the first quarter 2015. Since 2012, in the aggregate, Mississippi Power has incurred charges of $2.08 billion ($1.28 billion after tax) as a result of changes in the cost estimate for the Kemper IGCC through June 30, 2015.

Mississippi Power placed the combined cycle and the associated common facilities portion of the Kemper IGCC project in service in August 2014 and continues to focus on completing the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities. The in-service date for the remainder of the Kemper IGCC is currently expected to occur in the first half of 2016. The current cost estimate includes costs through March 31, 2016. As a result of the additional factors that have the potential to impact start-up and operational readiness activities for this first-of-a-kind technology as described herein, the risk of further schedule extensions and/or cost increases, which could be material, remains.

For additional information on the Kemper IGCC, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein.

On February 12, 2015, the Mississippi Supreme Court (Court) issued its decision in a legal challenge with respect to the Mississippi PSC's March 2013 order that authorized the collection of $156 million annually (2013 MPSC Rate Order) to be recorded as Mirror CWIP. The Court reversed the 2013 MPSC Rate Order, deemed the 2013

Settlement Agreement (defined below) between Mississippi Power and the Mississippi PSC unenforceable due to a lack of public notice for the related proceedings, and directed the Mississippi PSC to enter an order requiring Mississippi Power to refund the Mirror CWIP amounts collected pursuant to the 2013 MPSC Rate Order. As of June 30, 2015, $331 million had been collected by Mississippi Power. On March 12, 2015, Mississippi Power and the Mississippi PSC filed motions for rehearing, and, on June 11, 2015, the Court issued its final decision, rejecting both Mississippi Power's and the Mississippi PSC's motions for rehearing and requiring that a rate refund be made and that the Mirror CWIP rate be terminated. On July 7, 2015, the Mississippi PSC ordered that the Mirror CWIP rate be terminated effective July 20, 2015. Mississippi Power submitted a refund plan to the Mississippi PSC on July 21, 2015, which proposed two alternative refund plans for the Mississippi PSC's consideration: (1) bill credit with check option; or (2) check-only option. Hearings on the refund plan are scheduled to be held on August 6, 2015.

See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2015 Mississippi Supreme Court Decision" herein for additional information.

Prior to the Court's final decision on June 11, 2015, Mississippi Power sought alternate rate recovery and filed a rate case on May 15, 2015 (2015 Rate Case). Mississippi Power's 2015 Rate Case presented the Mississippi PSC with three alternative rate proposals: (i) a traditional rate case, (ii) a rate mitigation plan fixing rates through 2017 (RMP 2017), and (iii) a rate mitigation plan fixing rates through 2019 (RMP 2019). RMP 2019 contemplated the total Mirror CWIP funds collected would be used to offset the retail revenue requirements over the life of the plan. However, in light of the Court's mandate and the Mississippi PSC's July 7, 2015 order, RMP 2019 is no longer viable as originally proposed by Mississippi Power.

On May 20, 2015, SMEPA notified Mississippi Power of its termination of the asset purchase agreement (APA) between Mississippi Power and SMEPA whereby SMEPA previously agreed to purchase a 15% undivided interest in the Kemper IGCC. Mississippi Power previously received a total of $275 million of deposits from SMEPA that were required to be returned to SMEPA with interest in connection with the termination of the APA. On June 3, 2015, Southern Company, pursuant to its guarantee obligation, returned approximately $301 million to SMEPA. Subsequently, Mississippi Power issued an 18-month promissory note in the aggregate principal amount of approximately $301 million to Southern Company. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Termination of Proposed Sale of Undivided Interest to SMEPA" herein for additional information.

The return of approximately $301 million to SMEPA in June 2015 in connection with the termination of the APA, the required refund of the approximately $353 million of Mirror CWIP rate collections, including associated carrying costs, and the termination of the Mirror CWIP rates have adversely impacted Mississippi Power's ability to obtain financing needed for its business operations.

As a result, on July 10, 2015, Mississippi Power submitted a supplemental filing with the Mississippi PSC that includes a request for interim rates (Supplemental Notice) until such time as the Mississippi PSC renders a final decision on an additional alternative rate proposal (In-Service Asset Proposal). The Supplemental Notice was filed in response to the Mississippi PSC's July 7, 2015 order and presents the In-Service Asset Proposal for consideration by the Mississippi PSC. The In-Service Asset Proposal is based upon the test period of June 2015 to May 2016 and is 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 Supplemental Notice requests that the Mississippi PSC establish a scheduling order for consideration of permanent rates under the In-Service Asset Proposal. Evidentiary hearings on the interim rate relief are scheduled to be held on August 6, 2015.

See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2015 Rate Case" herein for additional information.

As of June 30, 2015, Mississippi Power's current liabilities exceeded current assets by approximately $898 million primarily due to $900 million of bank term loans scheduled to mature on April 1, 2016, $30 million of short-term debt, and the required refund of approximately $353 million in Mirror CWIP, which includes associated carrying

costs through June 30, 2015. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2015 Mississippi Supreme Court Decision" herein for additional information. In addition, Mississippi Power issued an 18-month promissory note in the aggregate principal amount of approximately $301 million to Southern Company that matures on December 2, 2016 in conjunction with the repayment of SMEPA's deposits with interest, following the termination of SMEPA's planned purchase of 15% of the Kemper IGCC project. Furthermore, Mississippi Power expects to fund the cash component of the Mirror CWIP refund with an intercompany loan from Southern Company. Mississippi Power intends to utilize operating cash flows and lines of credit (to the extent available) as well as loans and, under certain circumstances, equity contributions from Southern Company to fund Mississippi Power's short-term capital needs.

Mississippi Power continues to focus on several key performance indicators, including the construction, start-up, and rate recovery of the Kemper IGCC. In recognition that Mississippi Power's long-term financial success is dependent upon how well it satisfies its customers' needs, Mississippi Power's retail base rate mechanism, PEP, includes performance indicators that directly tie customer service indicators to Mississippi Power's allowed return. In addition to the PEP performance indicators, Mississippi Power focuses on other performance measures, including broader measures of customer satisfaction, plant availability, system reliability, and net income after dividends on preferred stock. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Key Performance Indicators" of Mississippi Power in Item 7 of the Form 10-K. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for information regarding revisions to the cost estimate for the Kemper IGCC and the Court's decision that have negatively impacted Mississippi Power's actual performance on net income after dividends on preferred stock, one of its key performance indicators, for 2015, as compared to the target.

RESULTS OF OPERATIONS

Net Income (Loss)

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(13)	(21.0)	$194	N/M

N/M-Not meaningful

Mississippi Power's net income after dividends on preferred stock for the second quarter 2015 was $49 million compared to $62 million for the corresponding period in 2014. The decrease was primarily related to $23 million in pre-tax charges ($14 million after tax) in the second quarter 2015 for revisions of the estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC above the $2.88 billion cost cap established by the Mississippi PSC, net of the DOE Grants and excluding the Cost Cap Exceptions. The decrease in net income was also related to a decrease in AFUDC equity, increases in non-fuel operations and maintenance expenses, an increase in depreciation and amortization, and a decrease in retail revenues primarily resulting from the Court's decision, partially offset by a decrease in interest expense.

For year-to-date 2015, net income after dividends on preferred stock was $84 million compared to a net loss of $110 million for the corresponding period in 2014. The increase was primarily related to $32 million in pre-tax charges ($20 million after tax) in 2015 compared to $380 million in pre-tax charges ($235 million after tax) in 2014 for revisions of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC above the $2.88 billion cost cap established by the Mississippi PSC, net of the DOE Grants and excluding the Cost Cap Exceptions. The increase in net income was also related to a decrease in interest expense, partially offset by a decrease in AFUDC equity, increases in non-fuel operations and maintenance expenses, an increase in depreciation and amortization, and a decrease in retail revenues primarily resulting from the Court's decision.

See Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined

Cycle" and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information. Also see "Interest Expense, Net of Amounts Capitalized" herein for additional information.

Retail Revenues

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(22)	(10.4)	$(61)	(14.6)

In the second quarter 2015, retail revenues were $189 million compared to $211 million for the corresponding period in 2014. For year-to-date 2015, retail revenues were $357 million compared to $418 million for the corresponding period in 2014.

Details of the changes in retail revenues were as follows:

	Second Quarter 2015		Year-to-Date 2015	
	(in millions)	*(% change)*	*(in millions)*	*(% change)*
Retail – prior year	$ 211		$ 418	
Estimated change resulting from –				
Rates and pricing	(6)	(2.7)	(9)	(2.2)
Sales decline	(1)	(0.6)	(5)	(1.2)
Weather	2	0.9	1	0.2
Fuel and other cost recovery	(17)	(8.0)	(48)	(11.4)
Retail – current year	$ 189	(10.4)%	$ 357	(14.6)%

Revenues associated with changes in rates and pricing decreased in the second quarter and year-to-date 2015 when compared to the corresponding periods in 2014 primarily due to $7 million and $11 million, respectively, of revenues associated with the Kemper IGCC cost recovery recognized in 2014, which ceased in 2015 as a result of the Court's decision, partially offset by $1 million in the second quarter 2015 and $2 million year-to-date 2015 in net revenues for the new energy efficiency cost recovery rate, which began in the fourth quarter 2014.

See Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" and "Retail Regulatory Matters – Performance Evaluation Plan" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information.

Revenues attributable to changes in sales decreased in the second quarter 2015 when compared to the corresponding period in 2014. Weather-adjusted KWH sales to residential customers decreased 0.5% in the second quarter 2015 due to lower customer usage, slightly offset by an increase in customers. Weather-adjusted KWH sales to commercial customers increased 2.6% in the second quarter 2015 due to higher customer usage and an increase in customers. KWH sales to industrial customers decreased 0.9% in the second quarter 2015 due to decreased usage by larger customers related to planned maintenance outages.

Revenues attributable to changes in sales decreased year-to-date 2015 when compared to the corresponding period in 2014. Weather-adjusted KWH energy sales to residential customers decreased 1.2% due to lower customer usage, slightly offset by an increase in customers. Weather-adjusted KWH energy sales to commercial customers decreased 0.2% due to lower customer usage slightly offset by an increase in customers. KWH energy sales to industrial customers increased 1.2% primarily due to increased usage by larger customers.

In the first quarter 2015, Mississippi Power updated its 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 discussed above reflect an adjustment to the estimated allocation of Mississippi Power's unbilled second quarter

and year-to-date 2014 KWH sales among customer classes that is consistent with the actual allocation in 2015. Without these adjustments, second quarter 2015 weather-adjusted residential KWH sales increased 4.0%, weather-adjusted commercial KWH sales decreased 1.5%, and industrial KWH sales decreased 2.1% as compared to the corresponding period in 2014. Also, without these adjustments, year-to-date 2015 weather-adjusted residential KWH sales decreased 3.3%, weather-adjusted commercial KWH sales decreased 5.1%, and industrial KWH sales remained flat as compared to the corresponding period in 2014.

Fuel and other cost recovery revenues decreased in the second quarter and year-to-date 2015 when compared to the corresponding periods in 2014, primarily as a result of lower recoverable fuel costs. See "Fuel and Purchased Power Expenses" herein for additional information. Recoverable fuel costs include fuel and purchased power expenses reduced by the fuel portion of wholesale revenues from energy sold to customers outside Mississippi Power's service territory. Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the energy component of purchased power costs, and do not affect net income.

Wholesale Revenues – Non-Affiliates

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(12)	(16.0)	$(31)	(18.0)

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of Mississippi Power's and the Southern Company system's generation, demand for energy within the Southern Company system's 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. Mississippi Power serves long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters" of Mississippi Power in Item 7 of the Form 10-K for additional information.

In the second quarter 2015, wholesale revenues from sales to non-affiliates were $63 million compared to $75 million for the corresponding period in 2014. For year-to-date 2015, wholesale revenues from sales to non-affiliates were $141 million compared to $172 million for the corresponding period in 2014. The decreases were primarily due to a decrease in energy revenues resulting from lower market prices and fuel cost.

Wholesale Revenues – Affiliates

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(2)	(10.0)	$2	4.7

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the IIC, as approved by the FERC. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

In the second quarter 2015, wholesale revenues from sales to affiliates were $18 million compared to $20 million for the corresponding period in 2014. The decrease was due to a $6 million decrease associated with lower natural gas prices, partially offset by a $4 million increase in KWH sales due to higher gas generation partially as a result of the Kemper IGCC combined cycle being in service since August 2014.

For year-to-date 2015, wholesale revenues from sales to affiliates were $45 million compared to $43 million for the corresponding period in 2014. The increase was due to an $18 million increase in KWH sales due to higher gas

generation partially as a result of the Kemper IGCC combined cycle being in service since August 2014, partially offset by a $16 million decrease associated with lower natural gas prices.

Fuel and Purchased Power Expenses

	Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
	(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
Fuel	$ (28)	(19.6)	$ (61)	(21.0)
Purchased power – non-affiliates	1	100.0	(10)	(76.9)
Purchased power – affiliates	(4)	(66.7)	(11)	(73.3)
Total fuel and purchased power expenses	$ (31)		$ (82)	

In the second quarter 2015, total fuel and purchased power expenses were $119 million compared to $150 million for the corresponding period in 2014. The decrease was due to a $28 million decrease in the average cost of fuel and purchased power and a $3 million decrease in the volume of KWHs purchased.

For year-to-date 2015, total fuel and purchased power expenses were $236 million compared to $318 million for the corresponding period in 2014. The decrease was due to a $72 million decrease in the average cost of fuel and purchased power and a $14 million decrease in the volume of KWHs purchased, partially offset by a $4 million increase in the volume of KWHs generated.

Fuel and purchased power energy transactions do not have a significant impact on earnings since energy expenses are generally offset by energy revenues through Mississippi Power's fuel cost recovery clause.

Details of Mississippi Power's generation and purchased power were as follows:

	Second Quarter 2015	Second Quarter 2014	**Year-to-Date 2015**	Year-to-Date 2014
Total generation *(millions of KWHs)*(*)	**4,109**	3,932	**8,455**	7,974
Total purchased power *(millions of KWHs)*	**114**	208	**227**	466
Sources of generation *(percent)*(*) –				
Coal	**18**	47	**20**	46
Gas	**82**	53	**80**	54
Cost of fuel, generated *(cents per net KWH)* –				
Coal	**4.14**	4.18	**3.64**	4.21
Gas(*)	**2.71**	3.62	**2.69**	3.61
Average cost of fuel, generated *(cents per net KWH)*(*)	**2.98**	3.90	**2.90**	3.91
Average cost of purchased power *(cents per net KWH)*(*)	**3.19**	3.33	**3.37**	5.87

(*) Includes energy produced during the test period for the Kemper IGCC which is accounted for in accordance with FERC guidance.

Fuel

In the second quarter 2015, fuel expense was $115 million compared to $143 million for the corresponding period in 2014. The decrease was primarily due to a 23.6% decrease in the average cost of fuel per KWH generated primarily due to higher gas-fired generation, including the Kemper IGCC combined cycle that was placed in service in August 2014, at lower natural gas prices, partially offset by a 4.9% increase in the volume of KWHs generated resulting from the availability of lower cost Mississippi Power units. The 4.9% increase in volume included an increase in gas-fired generation of 70.2%, partially offset by a decrease in coal-fired generation of 60.2%.

For year-to-date 2015, total fuel expense was $229 million compared to $290 million for the corresponding period in 2014. The decrease was primarily due to a 25.8% decrease in the average cost of fuel per KWH generated primarily due to higher gas-fired generation, including the Kemper IGCC combined cycle that was placed in service in August 2014, at lower natural gas prices, partially offset by a 6.1% increase in the volume of KWHs generated resulting from the availability of lower cost Mississippi Power units. The 6.1% increase in volume included an increase in gas-fired generation of 65.2%, offset by a decrease in coal-fired generation of 53.7%.

Purchased Power - Non-Affiliates

In the second quarter 2015, purchased power expense from non-affiliates was $2 million compared to $1 million for the corresponding period in 2014. The increase was primarily the result of a 57.6% increase in the average cost per KWH, offset by a 2.8% decrease in the volume of KWHs purchased due to an increase in Mississippi Power generation partially as a result of the Kemper IGCC combined cycle being placed in service in August 2014.

For year-to-date 2015, purchased power expense from non-affiliates was $3 million compared to $13 million for the corresponding period in 2014. The decrease was primarily the result of a 54.1% decrease in the volume of KWHs purchased due to an increase in Mississippi Power generation partially as a result of the Kemper IGCC combined cycle being placed in service in August 2014 and a 42.3% decrease in the average cost per KWH purchased as a result of 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 service territory, and the availability of the Southern Company system's generation.

Purchased Power - Affiliates

In the second quarter 2015, purchased power expense from affiliates was $2 million compared to $6 million for the corresponding period in 2014. The decrease was primarily due to a 58.3% decrease in the volume of KWHs purchased due to increased Mississippi Power generation partially as a result of the Kemper IGCC combined cycle being placed in service in August 2014, and a 24.7% decrease in the average cost per KWH purchased as a result of lower natural gas prices.

For year-to-date 2015, purchased power expense from affiliates was $4 million compared to $15 million for the corresponding period in 2014. The decrease was primarily due to a 50.0% decrease in the volume of KWHs purchased due to increased Mississippi Power generation partially as a result of the Kemper IGCC combined cycle being placed in service in August 2014, and a 41.5% decrease in the average cost per KWH purchased as a result of lower natural gas prices.

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

Other Operations and Maintenance Expenses

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$7	11.5	$19	15.2

In the second quarter 2015, other operations and maintenance expenses were $68 million compared to $61 million for the corresponding period in 2014. The increase was primarily due to a $7 million increase in generation maintenance expenses primarily related to scheduled outages.

For year-to-date 2015, other operations and maintenance expenses were $144 million compared to $125 million for the corresponding period in 2014. The increase was primarily due to a $6 million increase in generation

maintenance expenses including scheduled outages, a $5 million increase in employee compensation and benefits including pension, and a $5 million increase related to uncollectible expenses and customer incentives.

See Note (F) to the Condensed Financial Statements herein for additional information related to pension costs.

Depreciation and Amortization

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$6	25.0	$10	21.3

In the second quarter 2015, depreciation and amortization was $30 million compared to $24 million for the corresponding period in 2014. The increase was primarily due to a $2 million increase in depreciation related to increases in generation and distribution plant in service, a $2 million increase related to regulatory deferrals associated with Plant Daniel Units 3 and 4 and the Kemper IGCC, and a $1 million increase in ECO Plan amortization.

For year-to-date 2015, depreciation and amortization was $57 million compared to $47 million for the corresponding period in 2014. The increase was primarily due to a $4 million increase in depreciation related to increases in generation, transmission and distribution plant in service, a $4 million increase related to regulatory deferrals associated with Plant Daniel Units 3 and 4 and the Kemper IGCC, and a $2 million increase in ECO Plan amortization.

See Note 1 to the financial statements of Mississippi Power under "Depreciation, Depletion, and Amortization" in Item 8 of the Form 10-K for additional information. See Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information.

Taxes Other Than Income Taxes

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$3	15.0	$7	17.1

In the second quarter 2015, taxes other than income taxes were $23 million compared to $20 million for the corresponding period in 2014. The increase was primarily due to a $3 million increase in ad valorem taxes, partially offset by a $1 million decrease in franchise tax.

For year-to-date 2015, taxes other than income taxes were $48 million compared to $41 million for the corresponding period in 2014. The increase was primarily due to a $9 million increase in ad valorem taxes, partially offset by a $2 million decrease in franchise taxes.

The retail portion of ad valorem taxes is recoverable under Mississippi Power's ad valorem tax cost recovery clause and, therefore, does not affect net income.

Estimated Loss on Kemper IGCC

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$23	N/M	$(348)	(91.6)

N/M-Not meaningful

In the second quarter 2015 an estimated probable loss on the Kemper IGCC of $23 million was recorded at Mississippi Power. For year-to-date 2015 and year-to-date 2014, estimated probable losses on the Kemper IGCC of $32 million and $380 million, respectively, were recorded at Mississippi Power. These losses 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 DOE Grants and excluding the Cost Cap Exceptions.

See Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information.

Allowance for Equity Funds Used During Construction

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(12)	(32.4)	$(22)	(29.3)

In the second quarter 2015, AFUDC equity was $25 million compared to $37 million for the corresponding period in 2014. For year-to-date 2015, AFUDC equity was $53 million compared to $75 million for the corresponding period in 2014. The decreases are driven by a reduction in the AFUDC rate and by placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service in August 2014. See Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information regarding the Kemper IGCC.

Interest Expense, Net of Amounts Capitalized

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(43)	N/M	$(44)	N/M

N/M-Not meaningful

In the second quarter 2015, interest expense, net of amounts capitalized was ($30) million compared to $13 million for the corresponding period in 2014. For year-to-date 2015, interest expense, net of amounts capitalized was ($19) million compared to $25 million for the corresponding period in 2014. The decreases were primarily due to a $41 million decrease related to the termination of the APA between Mississippi Power and SMEPA which required the return of SMEPA's deposits at a lower rate of interest than accrued. Also contributing to the decrease was an increase in capitalized interest primarily resulting from carrying costs related to the Kemper IGCC. See Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information.

Income Taxes (Benefit)

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$—	—	$134	N/M

N/M-Not meaningful

In the second quarter 2015 and 2014, income taxes were $16 million. For year-to-date 2015, income taxes (benefit) were $20 million compared to $(114) million for the corresponding period in 2014. The change primarily reflects a

reduction in tax benefits related to the estimated probable losses on the construction of the Kemper IGCC recorded in 2014.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Mississippi Power's future earnings potential. The level of Mississippi Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Mississippi Power's business of selling electricity. These factors include Mississippi Power's ability to recover its prudently-incurred costs during a time of increasing costs, its ability to recover costs in a timely manner, and the completion and subsequent operation of the Kemper IGCC and the Plant Daniel scrubber project as well as other ongoing construction projects. Future earnings in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, new energy contracts with other utilities and other wholesale customers, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in Mississippi Power's service territory. Changes in regional and global economic conditions may impact sales for Mississippi Power as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Mississippi Power in Item 7 of the Form 10-K.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis or through market-based contracts. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

On April 16, 2015, the assets that supported coal generation at Plant Watson Units 4 and 5 were retired. The remaining net book value of these two units was approximately $32 million excluding the reserve for cost of removal. As of June 30, 2015, Mississippi Power reclassified the net carrying value of these assets from accumulated provision for depreciation to other regulatory assets, deferred, in accordance with an accounting order from the Mississippi PSC. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Other Matters – Sierra Club Settlement Agreement" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Other Matters – Sierra Club Settlement Agreement" in Item 8 of the Form 10-K for additional information.

Mississippi Power expects to recover through its rates the remaining book value of the retired assets and certain costs, including unusable inventory, associated with the retirements; however, the ultimate method and timing of recovery will be considered by the Mississippi PSC in future rate proceedings.

New Source Review Actions

See Note 3 to the financial statements of Mississippi Power under "Environmental Matters – New Source Review Actions" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements herein for additional information.

On June 25, 2015, the U.S. Department of Justice filed a joint stipulation between Alabama Power, the EPA, and the U.S. Department of Justice proposing to modify the 2006 consent decree to resolve all remaining claims for relief alleged in the case. If approved by the U.S. District Court for the Northern District of Alabama, Alabama

Power will, without admitting liability, operate subject to emission rates and a cap on certain units and requirements to use only natural gas at certain units, including a unit co-owned by Mississippi Power; retire certain units at Plants Gorgas and Barry; pay a $100,000 civil penalty; and invest $1.5 million in electric transportation infrastructure projects over three years.

The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

See Note 3 to the financial statements of Mississippi Power under "Other Matters – Sierra Club Settlement Agreement" in Item 8 of the Form 10-K for additional information.

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Mississippi Power in Item 7 of the Form 10-K for additional information regarding the EPA's proposed regulations governing emissions during startup, shutdown, or malfunction (SSM), the final MATS rule, and the Cross State Air Pollution Rule (CSAPR).

On June 12, 2015, the EPA published a final rule requiring affected states (including Alabama and Mississippi) to revise or remove state implementation plan (SIP) provisions regarding excess emissions that occur during periods of SSM by no later than November 22, 2016. The ultimate impact of the final rule will depend on the outcome of any legal challenges and the development and approval of SIPs by the affected states and cannot be determined at this time.

On June 29, 2015, the U.S. Supreme Court issued a decision finding that the EPA had failed to properly consider costs in its decision to regulate hazardous air pollutant emissions from electric generating units under the MATS rule and remanded the case to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The MATS rule remains in effect while the U.S. Court of Appeals for the District of Columbia Circuit and the EPA respond to the decision. The ultimate impact of this decision cannot be determined at this time.

On July 28, 2015, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion invalidating certain emissions budgets under the CSAPR Phase II emissions trading program for a number of states, including Alabama. The court's decision leaves the emissions trading program in place and remands the rule to the EPA for further action consistent with the court's decision. The court rejected all other pending challenges to the rule. The ultimate impact of this decision will depend on additional rulemaking and cannot be determined at this time.

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Mississippi Power in Item 7 of the Form 10-K for additional information regarding the EPA's and the U.S. Army Corps of Engineers' proposed rule revising the definition of waters of the U.S. under the Clean Water Act (CWA).

On June 29, 2015, the EPA and the U.S. Army Corps of Engineers jointly published a final rule revising the regulatory definition of waters of the U.S. for all 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 becomes effective August 28, 2015. The ultimate impact of the final rule will depend on the outcome of any legal challenges and the EPA's and the U.S. Army Corps of Engineers' field-level implementation of the rule and cannot be determined at this time.

Coal Combustion Residuals

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Coal Combustion Residuals" of Mississippi Power in Item 7 of the Form 10-K for additional information regarding the EPA's regulation of CCR.

On April 17, 2015, the EPA published the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule) in the Federal Register, setting October 19, 2015 as the effective date of the CCR Rule. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on Mississippi Power's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. Based on initial estimates, Mississippi Power recorded incremental asset retirement obligations (ARO) of approximately $95 million related to the CCR Rule in the second quarter 2015. As further analysis is performed, including evaluation of the expected timing and method of compliance and refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, Mississippi Power expects to periodically update these estimates. See Note (A) to the Condensed Financial Statements herein for additional information regarding Mississippi Power's AROs.

Global Climate Issues

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" of Mississippi Power in Item 7 of the Form 10-K for additional information regarding the EPA's proposed regulation of CO_2 from fossil-fuel-fired electric generating units.

On August 3, 2015, the EPA released pre-publication versions of two final rules that would limit CO_2 emissions from fossil fuel-fired electric generating units. One of the final rules contains specific emission standards governing CO_2 emissions from new, modified, and reconstructed units. The other final rule 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. At the same time, the EPA also proposed a federal plan and proposed model rule that states can adopt or that would be put in place if, in response to the final guidelines, a state either does not submit a state plan or its plan is not approved by the EPA. 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. Mississippi Power's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through market-based contracts. However, the ultimate financial and operational impact of the final rules on Mississippi Power cannot be determined at this time and will depend on numerous factors including the Southern Company system's ongoing review of the final rules; the outcome of any 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; the impact of future changes in generation and emissions related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

FERC Matters

Municipal and Rural Associations Tariff

See Note 3 to the financial statements of Mississippi Power under "FERC Matters" in Item 8 of the Form 10-K for additional information regarding a settlement agreement entered into by Mississippi Power regarding the establishment of a regulatory asset for Kemper IGCC-related costs. See Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for information regarding Mississippi Power's construction of the Kemper IGCC.

On March 31, 2015, Mississippi Power reached a settlement agreement with its wholesale customers and filed a request with the FERC to forgo the Municipal and Rural Associations cost-based electric tariff increase reflected in

the filing by, among other things, increasing the accrual of AFUDC in lieu of including CWIP in rate base. The settlement agreement, which was accepted by the FERC on May 13, 2015, provides that the additional accrual of AFUDC was effective April 1, 2015. The additional resulting AFUDC is projected to be approximately $11 million annually, of which $8 million relates to the Kemper IGCC. In addition, a settlement agreement entered into in 2014 and approved by the FERC allowed for an adjustment to the wholesale revenue requirement in the event the Kemper IGCC, or any substantial portion thereof, was placed in service before or after December 1, 2014. A regulatory asset account was recorded as a result of a portion of the Kemper IGCC being placed in service prior to the projected date. The March 31, 2015 settlement agreement provides that the regulatory asset will be amortized over nine months, beginning April 1, 2015.

Market-Based Rate Authority

Mississippi Power has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional operating companies (including Mississippi Power) and Southern Power filed a triennial market power analysis on June 30, 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional operating companies' (including Mississippi Power's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional operating companies and in some adjacent areas. To retain market-based rate authority, the FERC directed the traditional operating companies (including Mississippi Power) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional operating companies (including Mississippi Power) and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

Mississippi Power's rates and charges for service to retail customers are subject to the regulatory oversight of the Mississippi PSC. Mississippi Power's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as the Kemper IGCC, fuel and purchased power, energy efficiency programs, ad valorem taxes, property damage, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through Mississippi Power's base rates. See Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters" and "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under "Retail Regulatory Matters" and "Integrated Coal Gasification Combined Cycle" herein for additional information.

Renewables

In April and May 2015, Mississippi Power entered into separate PPAs for three solar facilities for a combined total of approximately 105 MWs. Mississippi Power would purchase all of the energy produced by the solar facilities for the 25-year term of the contracts. If approved by the Mississippi PSC, the projects are expected to be in service by the end of 2016 and the resulting energy purchases will be recovered through Mississippi Power's fuel cost recovery mechanism. The ultimate outcome of this matter cannot be determined at this time.

Performance Evaluation Plan

On March 17, 2015, Mississippi Power submitted its annual PEP lookback filing for 2014, which indicated no surcharge or refund. On March 26, 2015, the Mississippi PSC suspended the filing to allow it more time for review. The ultimate outcome of this matter cannot be determined at this time.

Ad Valorem Tax Adjustment

On April 23, 2015, Mississippi Power filed its annual ad valorem tax adjustment factor filing for 2015, which requested an annual rate decrease of 0.35%, or $2 million in annual retail revenues, primarily due to a decrease in average millage rates. On May 26, 2015, the Mississippi PSC suspended the filing to allow it more time to review. The ultimate outcome of this matter cannot be determined at this time.

Integrated Coal Gasification Combined Cycle

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K for information regarding Mississippi Power's construction of the Kemper IGCC.

Kemper IGCC Overview

Construction of Mississippi Power's Kemper IGCC is nearing completion and start-up activities will continue until the Kemper IGCC is placed in service. The Kemper IGCC will utilize an IGCC technology with an output capacity of 582 MWs. The Kemper IGCC will be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by Mississippi Power and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation in 2013. In connection with the Kemper IGCC, Mississippi Power constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the planned 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 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 using natural gas in August 2014 and continues to focus on completing the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, for which the in-service date is currently expected to occur in the first half of 2016. Recovery of the costs subject to the cost cap and the Cost Cap Exceptions remains subject to review and approval by the Mississippi PSC. Mississippi Power's Kemper IGCC 2010 project estimate, current cost estimate (which includes the impacts of the Court decision), and actual costs incurred as of June 30, 2015, as adjusted for the Court's decision, are as follows:

Cost Category	2010 Project Estimate[f]	Current Estimate	Actual Costs at June 30, 2015
		(in billions)	
Plant Subject to Cost Cap[a]	$ 2.40	$ 4.96	**$ 4.51**
Lignite Mine and Equipment	0.21	0.23	**0.23**
CO_2 Pipeline Facilities	0.14	0.11	**0.11**
AFUDC[b][c]	0.17	0.62	**0.52**
Combined Cycle and Related Assets Placed in Service – Incremental[d]	—	0.02	—
General Exceptions	0.05	0.10	**0.08**
Deferred Costs[c][e]	—	0.19	**0.15**
Total Kemper IGCC[a][c]	$ 2.97	$ 6.23	**$ 5.60**

(a) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, net of the DOE Grants and excluding the Cost Cap Exceptions. The Current Estimate and 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" for additional information. The Current Estimate and Actual Costs include the 15% undivided interest in the Kemper IGCC that was previously projected to be purchased by SMEPA. On May 20, 2015, SMEPA notified Mississippi Power of its termination of the APA and requested the return of a total of $275 million of deposits, which was returned with accrued interest on June 3, 2015.

(b) Mississippi Power's original estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC in 2012 as described in "Rate Recovery of Kemper IGCC Costs." The current estimate includes an approximately $11 million decrease in AFUDC due to a decrease in AFUDC rates resulting from an increase in short-term debt, partially offset by an $8 million increase in AFUDC related to a settlement agreement with the wholesale customers for cost-based rates under FERC's jurisdiction. See "FERC Matters" herein for additional information.

(c) Amounts in the Current Estimate reflect estimated costs through March 31, 2016.

(d) Incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service in August 2014, net of costs related to energy sales. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" for additional information.

(e) The 2012 MPSC CPCN Order approved deferral of non-capital Kemper IGCC-related costs during construction as described in "Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities."

(f) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities which was approved in 2011 by the Mississippi PSC.

Of the total costs, including post-in-service costs for the lignite mine, incurred as of June 30, 2015, $3.42 billion was included in property, plant, and equipment (which is net of the DOE Grants and estimated probable losses of $2.08 billion), $2 million in other property and investments, $58 million in fossil fuel stock, $41 million in materials and supplies, $198 million in other regulatory assets, $16 million in other deferred charges and assets, and $24 million in AROs in the balance sheet, with $1 million previously expensed.

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 DOE Grants and excluding the Cost Cap Exceptions. Mississippi Power recorded pre-tax charges to income for revisions to the cost estimate of $23 million ($14 million after tax) in the second quarter 2015 and $9 million ($6 million after tax) in the first quarter 2015. These amounts are in addition to charges totaling $868 million ($536 million after tax), $1.10 billion ($681 million after tax), and $78 million ($48 million after tax) in 2014, 2013, and 2012, respectively. The increases to the cost estimate in the first and second quarters of 2015 primarily reflected costs for increased efforts related to equipment rework, scope modifications, and the related additional labor costs in support of start-up and operational readiness activities. The current estimate includes costs through March 31, 2016. Any further extension of the in-service date is currently estimated to result in additional base costs of approximately $25 million to $30 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. Any further extension of the in-service date with respect to the Kemper IGCC 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 $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees, which are being deferred as regulatory assets and are estimated to total approximately $7 million per month.

Any further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (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). In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in Mississippi Power's statements of operations and these changes could be material.

Rate Recovery of Kemper IGCC Costs

The ultimate outcome of the rate recovery matters discussed herein, including the resolution of legal challenges, determinations of prudency, and the specific manner of recovery of prudently-incurred costs, cannot be determined at this time, but could have a material impact on Mississippi Power's results of operations, financial condition, and liquidity.

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 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 evaluation of the 2015 Rate Case and any alternative 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 Mississippi Power's financial statements.

2013 Settlement Agreement

In January 2013, Mississippi Power entered into a settlement agreement with the Mississippi PSC that, among other things, established 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. The 2013 Settlement Agreement also allowed Mississippi Power to secure alternate financing for costs not otherwise recovered in any Mississippi PSC rate proceedings contemplated by the 2013 Settlement Agreement. The Court found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. See "2015 Mississippi Supreme Court Decision" herein for additional information.

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's intent under the 2013 Settlement Agreement was to securitize (1) prudently-incurred costs in excess of the certificated cost estimate and up to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, (2) accrued AFUDC, and (3) other prudently-incurred costs, which include carrying costs from the

estimated in-service date until securitization is finalized and other costs not included in Mississippi Power's 2013 revision to the proposed rate recovery plan filed with the Mississippi PSC for the Kemper IGCC for cost recovery through 2020 (2013 Rate Mitigation Plan) as approved by the Mississippi PSC. The Court's decision did not impact Mississippi Power's ability to utilize alternate financing through securitization, the 2012 MPSC CPCN Order, or the February 2013 legislation. See "2015 Mississippi Supreme Court Decision" herein for additional information.

2013 MPSC Rate Order

Consistent with the terms of the 2013 Settlement Agreement, 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. 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 the in-service date. Mississippi Power will not record AFUDC on any additional costs of the Kemper IGCC that exceed the $2.88 billion cost cap, except for Cost Cap Exception amounts. Mississippi Power will continue to record AFUDC through the in-service date until directed to do otherwise by the Mississippi PSC.

In August 2014, Mississippi Power provided an analysis of the costs and benefits of placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service, including the expected accounting treatment for costs and revenues associated with the operation of the combined cycle as well as the treatment of revenues collected under the 2013 MPSC Rate Order. See "2015 Mississippi Supreme Court Decision" for additional information regarding the decision of the Court which discontinues the collection of rates under the 2013 MPSC Rate Order and requires the refund of all amounts previously collected.

In addition, Mississippi Power's August 2014 filing with the Mississippi PSC requested confirmation of Mississippi Power's accounting treatment by the Mississippi PSC of the continued accrual of AFUDC through the in-service date of the remainder of the Kemper IGCC. See "Regulatory Assets and Liabilities" for additional information. Any action by the Mississippi PSC that is inconsistent with the treatment requested by Mississippi Power could have a material impact on the results of operations, financial condition, and liquidity of Mississippi Power.

2015 Mississippi Supreme Court Decision

On February 12, 2015, the Court issued its decision in the legal challenge to the 2013 MPSC Rate Order. 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 March 12, 2015, Mississippi Power and the Mississippi PSC each filed motions for rehearing, both of which were denied on June 11, 2015. The Court's ruling remanded the matter to the Mississippi PSC to (1) fix by order the rates that were in existence prior to the 2013 MPSC Rate Order, (2) fix no rate increases until the Mississippi PSC is in compliance with the Court's ruling, and (3) enter an order refunding amounts collected under the 2013 MPSC Rate Order. Through June 30, 2015, Mississippi Power had collected $331 million through rates under the 2013 MPSC Rate Order and had accrued $22 million in associated carrying costs. On July 7, 2015, the Mississippi PSC ordered that the Mirror CWIP rate be terminated effective July 20, 2015. Mississippi Power submitted a refund plan to the Mississippi PSC on July 21, 2015, which proposed two alternative refund plans for the Mississippi PSC's consideration: (1) bill credit with check option; or (2) check-only option. Hearings on the refund plan are scheduled to be held on August 6, 2015.

2015 Rate Case

As a result of the 2015 Mississippi Supreme Court decision and the Mirror CWIP refund, the 2013 Rate Mitigation Plan is no longer viable. See "2015 Mississippi Supreme Court Decision" herein for additional information. On

May 15, 2015, Mississippi Power filed the 2015 Rate Case with the Mississippi PSC. This filing included three alternative rate proposals requesting an increase in retail rates and charges in connection with the Kemper IGCC: (i) a traditional rate case, (ii) a rate mitigation plan fixing rates through 2017 (RMP 2017), and (iii) a rate mitigation plan fixing rates through 2019 (RMP 2019). Under the traditional proposal, rates would increase above May 2015 levels by approximately 11.8%, or $114 million annually, effective June 1, 2015, and would be projected to increase approximately an additional 12.0%, or $120 million annually, effective June 1, 2016. The traditional proposal assumes termination of the Mirror CWIP rate and the refund of the Mirror CWIP regulatory liability over the period from May 2015 through May 2017. RMP 2017 presents revenue requirements calculated consistent with a rate mitigation plan authorized by Mississippi state law that would mitigate the Kemper IGCC's initial retail revenue impact over two years (June 1, 2015 through May 31, 2017). Under RMP 2017, rates would increase above May 2015 levels by approximately 2.6%, or $25 million annually, effective June 1, 2015, and approximately an additional 19.0%, or $197 million annually, effective June 1, 2016. This proposal assumes termination of the Mirror CWIP rate and the refund of the Mirror CWIP regulatory liability over the period from May 2015 through May 2017. In light of the Mississippi PSC's July 7, 2015 order, RMP 2019 is no longer viable as originally proposed by Mississippi Power.

On July 10, 2015, Mississippi Power filed a Supplemental Notice with the Mississippi PSC in response to the July 7, 2015 order of the Mississippi PSC. The Supplemental Notice presents an additional alternative rate proposal, In-Service Asset Proposal, for consideration by the Mississippi PSC. The In-Service Asset Proposal is based upon the test period of June 2015 to May 2016, is 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, and is designed to collect approximately $159 million annually. The Supplemental Notice requests that the In-Service Asset Proposal be implemented immediately as interim rates, subject to refund, until such time as the Mississippi PSC renders a final decision on the In-Service Asset Proposal and requests that the Mississippi PSC establish a scheduling order for consideration of permanent rates under the In-Service Asset Proposal. Evidentiary hearings on the interim rate relief are scheduled to be held on August 6, 2015.

The revenue requirements set forth in the alternative rate proposals exclude the costs of the Kemper IGCC related to the 15% undivided interest that was previously projected to be purchased by SMEPA. See "Termination of Proposed Sale of Undivided Interest to SMEPA" herein for additional information.

If the Mississippi PSC does not act on the Supplemental Notice or the 2015 Rate Case within 120 days of the Supplemental Notice filing, Mississippi Power expects to put one of the three viable alternative rate proposals into effect as temporary rates under bond and subject to refund pursuant to Mississippi state law.

Mississippi Power also expects to seek additional rate relief to address recovery of the remaining Kemper IGCC assets. In addition to current estimated costs at June 30, 2015 of $6.23 billion, Mississippi Power anticipates that it will incur additional costs after the Kemper IGCC in-service date until the Kemper IGCC cost recovery approach is finalized. These costs include, but are not limited to, regulatory costs and additional carrying costs which could be material. Recovery of these costs would be subject to approval by the Mississippi PSC.

Prudence Reviews

The Mississippi PSC's review of Kemper IGCC costs is ongoing. In August 2014, the Mississippi PSC ordered that a consolidated prudence determination of all Kemper IGCC costs be completed after the entire project has been placed in service and has demonstrated availability for a reasonable period of time as determined by the Mississippi PSC and the Mississippi Public Utilities Staff (MPUS). The Mississippi PSC has encouraged the parties to work in good faith to settle contested issues and Mississippi Power is working to reach a mutually acceptable resolution. On July 10, 2015, Mississippi Power submitted the Supplemental Notice to the Mississippi PSC. The Supplemental Notice requests that the Mississippi PSC establish a scheduling order for review of the In-Service Asset Proposal. Mississippi Power expects the Mississippi PSC to address the In-Service Asset Proposal before the end of 2015, although Mississippi Power believes that such a prudence finding is not required for

interim rate relief to be granted. See "2015 Mississippi Supreme Court Decision" and "2015 Rate Case" 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. As of June 30, 2015, the regulatory asset balance associated with the Kemper IGCC was $198 million. The projected balance at March 31, 2016 is estimated to total approximately $276 million. The amortization period for any such costs approved for recovery remains subject to approval by the Mississippi PSC.

See "2015 Mississippi Supreme Court Decision" herein for additional information related to the July 7, 2015 Mississippi PSC order terminating the Mirror CWIP rate and requiring refund of collections under Mirror CWIP.

See Note 1 to the financial statements of Mississippi Power under "Regulatory Assets and Liabilities" in Item 8 of the Form 10-K for additional information.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, Mississippi Power will own 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. See Note 1 to the financial statements of Mississippi Power under "Asset Retirement Obligations and Other Costs of Removal" and "Variable Interest Entities" in Item 8 of the Form 10-K for additional information.

In addition, Mississippi Power 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 has entered into agreements with Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tengrys, LLC, pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC. The agreements with Denbury and Treetop provide termination rights as Mississippi Power has not satisfied its contractual obligation to deliver captured CO_2 by May 11, 2015. Since May 11, 2015, Mississippi Power has been engaged in ongoing discussions with its off-takers regarding the status of the CO_2 delivery schedule as well as other issues related to the respective agreements. As a result of discussions with Treetop, on August 3, 2015, Mississippi Power agreed to amend certain provisions of their agreement that do not affect pricing or minimum purchase quantities. Any termination or material modification of these agreements could result in a material reduction in future chemical product sales revenues and could have a material financial impact

on Mississippi Power to the extent Mississippi Power is not able to enter into other similar contractual arrangements.

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

Termination of Proposed Sale of Undivided Interest to SMEPA

In 2010 and as amended in 2012, Mississippi Power and SMEPA entered into an APA whereby SMEPA agreed to purchase a 15% undivided interest in the Kemper IGCC. On May 20, 2015, SMEPA notified Mississippi Power of its termination of the APA between Mississippi Power and SMEPA. Mississippi Power previously received a total of $275 million of deposits from SMEPA that were required to be returned to SMEPA with interest in connection with the termination of the APA. On June 3, 2015, Southern Company, pursuant to its guarantee obligation, returned approximately $301 million to SMEPA. Subsequently, Mississippi Power issued an 18-month promissory note in the aggregate principal amount of approximately $301 million to Southern Company.

Income Tax Matters

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Income Tax Matters" of Mississippi Power in Item 7 of the Form 10-K for additional information.

Section 174 Research and Experimental Deduction

Southern Company, on behalf of Mississippi Power, reflected deductions for research and experimental (R&E) expenditures related to the Kemper IGCC in its federal income tax calculations for 2013 and 2014. In May 2015, Southern Company amended its 2008 through 2013 federal income tax returns to include deductions for Kemper IGCC-related R&E expenditures. Due to the uncertainty related to this tax position, Mississippi Power had unrecognized tax benefits associated with these R&E deductions totaling approximately $390 million as of June 30, 2015. See Note 5 to the financial statements of Mississippi Power under "Unrecognized Tax Benefits" in Item 8 of the Form 10-K and Notes (B) and (G) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" and "Unrecognized Tax Benefits – Section 174 Research and Experimental Deduction," respectively, herein for additional information. The ultimate outcome of this tax matter cannot be determined at this time.

Other Matters

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

The ultimate outcome of such pending or potential litigation against Mississippi Power cannot be predicted at this time; however, for current proceedings not specifically reported in Note (B) to the Condensed Financial Statements herein or in Note 3 to the financial statements of Mississippi Power in Item 8 of the Form 10-K, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Mississippi Power's financial statements. See Note (B) to the Condensed Financial Statements herein for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Mississippi Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Mississippi Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Mississippi Power's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Mississippi Power in Item 7 of the Form 10-K for a complete discussion of Mississippi Power's critical accounting policies and estimates related to Electric Utility Regulation, Contingent Obligations, Unbilled Revenues, Pension and Other Postretirement Benefits, and AFUDC.

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

During 2015, 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 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 DOE Grants and excluding the Cost Cap Exceptions.

As a result of the revisions to the cost estimate, Mississippi Power recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC of $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, Mississippi Power has incurred charges of $2.08 billion ($1.28 billion after tax) as a result of changes in the cost estimate for the Kemper IGCC through June 30, 2015.

Mississippi Power has experienced, and may continue to experience, material changes in the cost estimate for the Kemper IGCC. In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in Mississippi Power's statements of operations and these changes could be material. Any further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (including major equipment failure and system integration), and/or operational performance (including, but not limited to, additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC).

Mississippi Power's revised cost estimate includes costs through March 31, 2016. Any further extension of the in-service date is currently estimated to result in additional base costs of approximately $25 million to $30 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. Any further extension of the in-service date with respect to the Kemper IGCC 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 $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting fees and legal fees which are being deferred as regulatory assets and are estimated to total approximately $7 million per month.

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 Mississippi Power's results of operations, Mississippi Power considers these items to be critical accounting estimates. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information.

Asset Retirement Obligations

AROs are computed as the fair value of the 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, primarily ash ponds. In addition, Mississippi Power has retirement obligations related to various landfill sites, underground storage tanks, deep injection wells, water wells, substation removal, mine reclamation, and asbestos removal. Mississippi Power 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.

On April 17, 2015, the EPA published the final CCR Rule in the Federal Register, setting October 19, 2015 as the effective date of the CCR Rule. Therefore, Mississippi Power recorded new AROs for facilities that are subject to the CCR Rule. The cost estimates are based on information that was known as of June 30, 2015 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. As further analysis is performed, including evaluation of the expected timing and method of compliance and refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, Mississippi Power expects to periodically update these estimates. Given the significant judgment involved in estimating AROs, Mississippi Power considers the liabilities for AROs to be critical accounting estimates.

See Note 1 to the financial statements of Mississippi Power under "Asset Retirement Obligations and Other Costs of Removal" in Item 8 of the Form 10-K and Note (A) to the Condensed Financial Statements under "Asset Retirement Obligations" herein for additional information.

Recently Issued Accounting Standards

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers*, revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. Mississippi Power continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*. The ASU requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. Mississippi Power currently reflects unamortized debt issuance costs in other deferred charges and assets on its

balance sheet. Upon adoption, the reclassification will not have a material impact on the results of operations, financial position, or cash flows of Mississippi Power.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Overview" of Mississippi Power in Item 7 of the Form 10-K and FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" herein for additional information. Mississippi Power's financial condition was adversely affected by the return of approximately $301 million of interest bearing refundable deposits to SMEPA in June 2015 in connection with the termination of the APA. In addition, the required refund of Mirror CWIP rate collections, which as of June 30, 2015 was approximately $353 million including associated carrying costs, and the termination of the Mirror CWIP rate will further adversely impact Mississippi Power's financial condition and its ability to obtain financing needed for normal business operations and completion of the Kemper IGCC. Earnings for the six months ended June 30, 2015 were negatively affected by revisions to the cost estimate for the Kemper IGCC and the Court's decision to reverse the 2013 MPSC Rate Order. Earnings for the six months ended June 30, 2014 were negatively affected by revisions to the cost estimate for the Kemper IGCC.

In addition to funding normal business operations and projected capital expenditures, Mississippi Power's cash requirements primarily consist of $900 million of bank term loans scheduled to mature on April 1, 2016, $30 million of short-term debt, and the required refund of approximately $353 million in Mirror CWIP, which includes associated carrying costs. In addition, Mississippi Power issued an 18-month promissory note to Southern Company in the aggregate principal amount of approximately $301 million related to the refund to SMEPA and expects to enter into a similar promissory note with Southern Company to fund the Mirror CWIP refund. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Termination of Proposed Sale of Undivided Interest to SMEPA," "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order," " – 2015 Mississippi Supreme Court Decision," and " – 2015 Rate Case" herein for additional information. For the three-year period from 2015 through 2017, Mississippi Power's capital expenditures and debt maturities are expected to materially exceed operating cash flows. In addition to the Kemper IGCC, projected capital expenditures in that period include investments to maintain existing generation facilities, to add environmental equipment for existing generating units, including the Plant Daniel scrubber project, to add or change fuel sources for certain existing units, and to expand and improve transmission and distribution facilities. See "Sources of Capital" herein for additional information.

Through June 30, 2015, Mississippi Power has incurred non-recoverable cash expenditures of $1.62 billion and is expected to incur approximately $0.46 billion in additional non-recoverable cash expenditures through completion of the Kemper IGCC.

During the first six months of 2015, Mississippi Power received $75 million in equity contributions from Southern Company. In April 2015, Mississippi Power entered into two floating rate bank loans with a maturity date of April 1, 2016, in an aggregate principal amount of $475 million, bearing interest based on one-month LIBOR. The proceeds of these loans were used for the repayment of term loans in an aggregate principal amount of $275 million, working capital, and other general corporate purposes. Mississippi Power also amended three outstanding floating rate bank loans for an aggregate principal amount of $425 million which, among other things, extended the maturity dates from various dates in 2015 to April 1, 2016. On June 3, 2015, Mississippi Power issued an 18-month promissory note in the aggregate principal amount of approximately $301 million to Southern Company as a result of Southern Company's refund of approximately $301 million in deposits and associated interest to SMEPA in connection with the termination of the APA. Mississippi Power intends to utilize operating cash flows and lines of credit (to the extent available) as well as loans and, under certain circumstances, equity contributions from Southern Company to fund Mississippi Power's short-term capital needs. See "Capital Requirements and Contractual Obligations," "Sources of Capital," and "Financing Activities" herein for additional information.

Net cash provided from operating activities totaled $309 million for the first six months of 2015, an increase of $131 million as compared to the corresponding period in 2014. The increase in cash provided from operating activities is primarily due to R&E tax deductions and bonus depreciation reducing tax payments, an increase in fuel recovery, and a decrease in receivables, partially offset by the timing of payments for accounts payable and fuel purchases. See Notes (B) and Note (G) to the Condensed Financial Statements herein for additional information. Net cash used for investing activities totaled $460 million for the first six months of 2015 primarily due to gross property additions related to the Kemper IGCC and the Plant Daniel scrubber project. Net cash provided from financing activities totaled $230 million for the first six months of 2015 primarily due to short-term bank loans, capital contributions from Southern Company, and short-term borrowings, partially offset by redemptions of long-term debt. Fluctuations in cash flow from financing activities vary from period to period based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for the first six months of 2015 include a decrease in securities due within one year of $349 million, primarily due to refinancing or replacing maturing long-term debt with short-term loans. Additionally, long-term debt increased $301 million and interest-bearing refundable deposit decreased $275 million, due to an intercompany loan for repayment of the SMEPA deposits and interest. See "Sources of Capital" herein for additional information. Total property, plant, and equipment increased $439 million; other regulatory assets, deferred increased $97 million; and the Mirror CWIP regulatory liability increased $82 million primarily associated with construction, operation, and collections related to the Kemper IGCC. See – "Integrated Coal Gasification Combined Cycle" herein for additional information. Income taxes receivable, non-current; accrued income taxes; accumulated deferred income taxes, a portion of which is reflected in other deferred charges and assets, and other deferred credits and liabilities increased primarily due to R&E tax deductions and the related reserve. Additional changes include increases in notes payable primarily due to new short-term bank loans and asset retirement obligations due to the CCR Rule. Total common stockholder's equity increased $164 million primarily due to the receipt of $75 million in capital contributions from Southern Company and due to net income during the second quarter 2015.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Mississippi Power in Item 7 of the Form 10-K for a description of Mississippi Power's capital requirements for its construction program, including estimated capital expenditures for new generating resources and to comply with existing environmental statutes and regulations, scheduled maturities of long-term debt, as well as related interest, leases, purchase commitments, derivative obligations, preferred stock dividends, trust funding requirements, and unrecognized tax benefits. Approximately $900 million will be required through June 30, 2016 to fund maturities of bank term loans scheduled to mature on April 1, 2016 and $30 million in short-term debt. In addition, Mississippi Power will be required to refund its Mirror CWIP rate collections of approximately $353 million as of June 30, 2015, including associated carrying costs. See "Sources of Capital" herein for additional information.

The construction program of Mississippi Power is currently estimated to be $1.0 billion in 2015, $354 million in 2016, and $229 million for 2017, which includes expenditures related to the construction of the Kemper IGCC of $801 million in 2015 and $150 million in 2016.

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. See Note (B) to the Condensed Financial Statements under "Integrated Coal

Gasification Combined Cycle – Kemper IGCC Schedule and Cost Estimate" herein for additional information and further risks related to the estimated schedule and costs and rate recovery for the Kemper IGCC.

Sources of Capital

Except as described herein, Mississippi Power plans to obtain the funds required for construction and other purposes from operating cash flows and lines of credit (to the extent available) as well as loans and, under certain circumstances, equity contributions from Southern Company. Mississippi Power's financial condition was adversely affected by the issuance of an 18-month promissory note to Southern Company related to the return of approximately $301 million of interest bearing refundable deposits to SMEPA in June 2015 in connection with the termination of the APA. In addition, the required refund of Mirror CWIP rate collections of approximately $353 million as of June 30, 2015, including associated carrying costs, and the termination of the Mirror CWIP rate have further adversely impacted Mississippi Power's financial condition and its ability to obtain funds needed for normal business operations and completion of the Kemper IGCC. 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 MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" and – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" and " – 2015 Mississippi Supreme Court Decision" of Mississippi Power in Item 7 of the Form 10-K and herein for additional information.

Mississippi Power received $245 million of DOE Grants in prior years that were used for the construction of the Kemper IGCC. An additional $25 million of DOE Grants is expected to be received for commercial operation of the Kemper IGCC. In addition, see Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K for information regarding legislation related to the securitization of certain costs of the Kemper IGCC.

In April 2015, Mississippi Power entered into two floating rate bank loans with a maturity date of April 1, 2016, in an aggregate principal amount of $475 million, bearing interest based on one-month LIBOR. The proceeds of these loans were used for the repayment of term loans in an aggregate principal amount of $275 million, working capital, and other general corporate purposes. Mississippi Power also amended three outstanding floating rate bank loans for an aggregate principal amount of $425 million which, among other things, extended the maturity dates from various dates in 2015 to April 1, 2016. As of June 30, 2015, Mississippi Power's current liabilities exceeded current assets by approximately $898 million primarily due to $900 million of bank term loans scheduled to mature on April 1, 2016, $30 million of short-term debt, and the required refund of approximately $353 million in Mirror CWIP, which includes associated carrying costs through June 30, 2015. Mississippi Power intends to utilize operating cash flows and lines of credit (to the extent available) as well as loans and, under certain circumstances, equity contributions from Southern Company to fund Mississippi Power's short-term capital needs.

At June 30, 2015, Mississippi Power had approximately $212 million of cash and cash equivalents. Committed credit arrangements with banks at June 30, 2015 were as follows:

Expires				Executable Term Loans		Due Within One Year	
2015	2016	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)		*(in millions)*		*(in millions)*		*(in millions)*	
$ 40	$ 255	$ 295	$ 265	$ 30	$ 40	$ 70	$ 225

See Note 6 to the financial statements of Mississippi Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information.

A portion of the $265 million unused credit arrangements with banks is allocated to provide liquidity support to Mississippi Power's variable rate pollution control revenue bonds and commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of June 30, 2015 was approximately $40 million.

Most of these bank credit arrangements contain covenants that limit debt levels and typically contain cross default provisions to other indebtedness (including guarantee obligations) of Mississippi Power. Such cross default provisions to other indebtedness would trigger an event of default if Mississippi Power defaulted on indebtedness or guarantee obligations over a specified threshold. Mississippi Power is currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowing.

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

To the extent available, Mississippi Power may seek to utilize a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of Mississippi Power and the other traditional operating companies. Proceeds from such issuances for the benefit of Mississippi Power would be loaned directly to Mississippi Power. The obligations of each company under these arrangements are several and there is no cross-affiliate credit support.

Details of short-term borrowings were as follows:

	Short-term Debt at June 30, 2015		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)*
Short-term bank debt	$ 505	1.4%	$ 460	1.4%	$ 505

(*) Average and maximum amounts are based upon daily balances during the three-month period ended June 30, 2015.

Credit Rating Risk

Mississippi Power does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that 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 sales, fuel transportation and storage, and energy price risk management. At June 30, 2015, the maximum potential collateral requirements under these contracts at a rating of BBB- and/or Baa3 was not material. The maximum potential collateral requirements at a rating below BBB- and/or Baa3 equaled approximately $282 million. Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade has impacted and may continue to impact Mississippi Power's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

On June 5, 2015, Fitch downgraded the long-term issuer default rating of Mississippi Power to BBB+ from A-. Fitch maintained the negative ratings outlook for Mississippi Power.

Subsequent to June 30, 2015, S&P placed its ratings of Southern Company and the traditional operating companies (including Mississippi Power) on CreditWatch with negative implications.

Financing Activities

In March 2015, Mississippi Power repaid at maturity a $75 million bank term loan.

In April 2015, Mississippi Power entered into two floating rate bank loans with a maturity date of April 1, 2016, in an aggregate principal amount of $475 million, bearing interest based on one-month LIBOR. The proceeds of these loans were used for the repayment of term loans in an aggregate principal amount of $275 million, working capital, and other general corporate purposes, including Mississippi Power's ongoing construction program. Mississippi Power also amended three outstanding floating rate bank loans for an aggregate principal amount of $425 million which, among other things, extended the maturity dates from various dates in 2015 to April 1, 2016.

In June 2015, Mississippi Power issued an 18-month floating rate promissory note to Southern Company bearing interest based on one-month LIBOR. This note was for an aggregate principal amount of approximately $301 million, the amount paid by Southern Company to SMEPA pursuant to Southern Company's guarantee of the return of SMEPA's deposit in connection with the termination of the APA. See Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle – Termination of Proposed Sale of Undivided Interest to SMEPA" herein for additional information.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	**2015**	2014
	(in millions)		*(in millions)*	
Operating Revenues:				
Wholesale revenues, non-affiliates	**$ 250**	$ 260	**$ 481**	$ 538
Wholesale revenues, affiliates	**85**	68	**199**	140
Other revenues	**2**	1	**4**	2
Total operating revenues	**337**	329	**684**	680
Operating Expenses:				
Fuel	**105**	118	**243**	243
Purchased power, non-affiliates	**18**	17	**34**	45
Purchased power, affiliates	**4**	16	**14**	46
Other operations and maintenance	**69**	69	**121**	122
Depreciation and amortization	**60**	52	**118**	103
Taxes other than income taxes	**6**	6	**12**	11
Total operating expenses	**262**	278	**542**	570
Operating Income	**75**	51	**142**	110
Other Income and (Expense):				
Interest expense, net of amounts capitalized	**(23)**	(22)	**(45)**	(44)
Other income (expense), net	**1**	—	**1**	—
Total other income and (expense)	**(22)**	(22)	**(44)**	(44)
Earnings Before Income Taxes	**53**	29	**98**	66
Income taxes (benefit)	**1**	(3)	**13**	—
Net Income	**52**	32	**85**	66
Less: Net income attributable to noncontrolling interests	**6**	1	**6**	2
Net Income Attributable to Southern Power Company	**$ 46**	$ 31	**$ 79**	$ 64

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	**2015**	2014
	(in millions)		*(in millions)*	
Net Income	**$ 52**	$ 32	**$ 85**	$ 66
Other comprehensive income (loss)	**—**	—	**—**	—
Less: Comprehensive income attributable to noncontrolling interests	**6**	1	**6**	2
Comprehensive Income Attributable to Southern Power Company	**$ 46**	$ 31	**$ 79**	$ 64

The accompanying notes as they relate to Southern Power are an integral part of these consolidated financial statements.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Six Months Ended June 30,	
	2015	2014
	(in millions)	
Operating Activities:		
Net income	**$ 85**	$ 66
Adjustments to reconcile net income to net cash provided from operating activities —		
Depreciation and amortization, total	**121**	105
Deferred income taxes	**59**	(3)
Investment tax credits	**153**	26
Amortization of investment tax credits	**(10)**	(5)
Deferred revenues	**(21)**	(24)
Accrued income taxes, non-current	**100**	—
Other, net	**10**	7
Changes in certain current assets and liabilities —		
-Receivables	**(26)**	(34)
-Fossil fuel stock	**5**	(1)
-Prepaid income taxes	**(102)**	21
-Other current assets	**—**	(1)
-Accounts payable	**(31)**	24
-Accrued taxes	**(110)**	7
-Other current liabilities	**18**	5
Net cash provided from operating activities	**251**	193
Investing Activities:		
Plant acquisitions	**(408)**	(213)
Property additions	**(154)**	(11)
Change in construction payables	**38**	(3)
Payments pursuant to long-term service agreements	**(45)**	(23)
Other investing activities	**(1)**	(11)
Net cash used for investing activities	**(570)**	(261)
Financing Activities:		
Increase (decrease) in notes payable, net	**(195)**	73
Proceeds — Senior notes	**650**	—
Distributions to noncontrolling interests	**(1)**	—
Contributions from noncontrolling interests	**78**	7
Payment of common stock dividends	**(65)**	(66)
Other financing activities	**(3)**	9
Net cash provided from financing activities	**464**	23
Net Change in Cash and Cash Equivalents	**145**	(45)
Cash and Cash Equivalents at Beginning of Period	**75**	69
Cash and Cash Equivalents at End of Period	**$ 220**	$ 24
Supplemental Cash Flow Information:		
Cash paid (received) during the period for —		
Interest (net of $1 and $- capitalized for 2015 and 2014, respectively)	**$ 35**	$ 43
Income taxes, net	**(72)**	(59)
Noncash transactions — Accrued property additions at end of period	**38**	5

The accompanying notes as they relate to Southern Power are an integral part of these consolidated financial statements.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Assets	At June 30, 2015	At December 31, 2014
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 220**	$ 75
Receivables —		
Customer accounts receivable	**106**	77
Other accounts receivable	**11**	15
Affiliated companies	**40**	34
Fossil fuel stock, at average cost	**17**	22
Materials and supplies, at average cost	**59**	58
Prepaid income taxes	**122**	19
Deferred income taxes, current	**144**	306
Other current assets	**16**	21
Total current assets	**735**	627
Property, Plant, and Equipment:		
In service	**6,047**	5,657
Less accumulated provision for depreciation	**1,125**	1,035
Plant in service, net of depreciation	**4,922**	4,622
Construction work in progress	**201**	11
Total property, plant, and equipment	**5,123**	4,633
Other Property and Investments:		
Goodwill	**2**	2
Other intangible assets, net of amortization of $10 and $8 at June 30, 2015 and December 31, 2014, respectively	**69**	47
Total other property and investments	**71**	49
Deferred Charges and Other Assets:		
Prepaid long-term service agreements	**141**	124
Other deferred charges and assets — affiliated	**13**	5
Other deferred charges and assets — non-affiliated	**143**	112
Total deferred charges and other assets	**297**	241
Total Assets	**$ 6,226**	$ 5,550

The accompanying notes as they relate to Southern Power are an integral part of these consolidated financial statements.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholders' Equity	**At June 30, 2015**	At December 31, 2014
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 525**	$ 525
Notes payable	**8**	195
Accounts payable —		
Affiliated	**65**	78
Other	**55**	30
Accrued income taxes	**7**	72
Accrued interest	**31**	30
Other current liabilities	**53**	17
Total current liabilities	**744**	947
Long-term Debt	**1,737**	1,095
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**760**	863
Accumulated deferred investment tax credits	**693**	601
Accrued income taxes, non-current	**100**	—
Deferred capacity revenues — affiliated	**9**	15
Other deferred credits and liabilities — affiliated	**—**	1
Other deferred credits and liabilities — non-affiliated	**22**	18
Total deferred credits and other liabilities	**1,584**	1,498
Total Liabilities	**4,065**	3,540
Redeemable Noncontrolling Interest	**41**	39
Common Stockholder's Equity:		
Common stock, par value $.01 per share —		
Authorized — 1,000,000 shares		
Outstanding — 1,000 shares	**—**	—
Paid-in capital	**1,176**	1,176
Retained earnings	**587**	573
Accumulated other comprehensive income	**4**	3
Total common stockholder's equity	**1,767**	1,752
Noncontrolling Interest	**353**	219
Total Stockholders' Equity	**2,120**	1,971
Total Liabilities and Stockholders' Equity	**$ 6,226**	$ 5,550

The accompanying notes as they relate to Southern Power are an integral part of these consolidated financial statements.

OVERVIEW

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 continually seeks opportunities to execute its strategy to create value through various transactions including acquisitions and sales of assets, construction of new power plants, and entry into PPAs primarily with investor-owned utilities, independent power producers, municipalities, and electric cooperatives. In general, Southern Power has constructed or acquired new generating capacity only after entering into long-term PPAs for the new facilities.

During the six months ended June 30, 2015, Southern Power acquired approximately 353 MWs of additional solar facilities including the five Georgia construction projects located in Taylor and Butler Counties, as well as the Lost Hills, Blackwell, and North Star projects located in California. Southern Power also entered into an agreement to acquire an approximately 299-MW wind facility, located in Oklahoma, contingent upon certain construction and project milestones. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Acquisitions" and "Construction Projects" herein for additional information.

Southern Power continues to focus on several key performance indicators. These indicators include peak season equivalent forced outage rate, contract availability, and net income. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Key Performance Indicators" of Southern Power in Item 7 of the Form 10-K.

RESULTS OF OPERATIONS

Net Income

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$15	48.4	$15	23.4

Net income attributable to Southern Power for the second quarter 2015 was $46 million compared to $31 million for the corresponding period in 2014. The increase was primarily due to increased revenue and lower fuel and purchased power expenses.

Net income attributable to Southern Power for year-to-date 2015 was $79 million compared to $64 million for the corresponding period in 2014. The increase was primarily due to a decrease in purchased power expenses, partially offset by increases in depreciation and income taxes.

Wholesale Revenues – Non-Affiliates

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$(10)	(3.8)	$(57)	(10.6)

Wholesale revenues from sales to non-affiliates will vary depending on the energy demand of those customers and their generation capacity, as well as the market prices of wholesale energy compared to the cost of Southern Power's energy. Increases and decreases in revenues under PPAs 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.

Wholesale revenues from non-affiliates for the second quarter 2015 were $250 million compared to $260 million for the corresponding period in 2014. The decrease was due to a $5 million decrease in energy sales, primarily as a result of decreased fuel costs passed through in PPA revenues due to lower natural gas prices, partially offset by increased sales volumes and new solar PPAs. The decrease in energy revenues reflects a 14% decrease in the average price of energy, partially offset by a 12% increase in KWH sales. In addition, capacity revenues decreased $5 million primarily due to PPA expirations.

Wholesale revenues from non-affiliates for year-to-date 2015 were $481 million compared to $538 million for the corresponding period in 2014. The decrease was due to a $44 million decrease in energy sales, primarily as a result of decreased fuel costs passed through in PPA revenues due to lower natural gas prices, partially offset by increased sales volumes and new solar PPAs. The decrease in energy revenues reflects a 17% decrease in the average price of energy, partially offset by a 5% increase in KWH sales. In addition, capacity revenues decreased $13 million primarily due to PPA expirations.

Wholesale Revenues – Affiliates

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$17	25.0	$59	42.1

Wholesale revenues from sales to affiliate companies will vary depending on demand and the availability and cost of generating resources at each company. Sales to affiliate companies that are not covered by PPAs are made in accordance with the IIC, as approved by the FERC.

Wholesale revenues from affiliates for the second quarter 2015 were $85 million compared to $68 million for the corresponding period in 2014. The increase was the result of a $10 million increase in energy revenues and a $7 million increase in capacity revenues. The increase in energy revenues is primarily the result of increased sales volume under the IIC as a result of lower natural gas prices, which increased demand for Southern Power Company's resources. The increase in energy revenues reflects a 61% increase in KWH sales, partially offset by a 21% decrease in the average price of energy. The increase in capacity revenues was primarily the result of new PPAs.

Wholesale revenues from affiliates for year-to-date 2015 were $199 million compared to $140 million for the corresponding period in 2014. The increase was the result of a $50 million increase in energy revenues and a $9 million increase in capacity revenues. The increase in energy revenues is primarily the result of increased sales volume under the IIC as a result of lower natural gas prices, which increased demand for Southern Power Company's resources. The increase in energy revenues reflects a 110% increase in KWH sales, partially offset by a 22% decrease in the average price of energy. The increase in capacity revenues was primarily the result of new PPAs.

Fuel and Purchased Power Expenses

	Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
	(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
Fuel	$ (13)	(11.0)	$ —	—
Purchased power – non-affiliates	1	5.9	(11)	(24.4)
Purchased power – affiliates	(12)	(75.0)	(32)	(69.6)
Total fuel and purchased power expenses	$ (24)		$ (43)	

Southern Power's PPAs for natural gas-fired generation generally provide that the purchasers are responsible for substantially all of the cost of fuel. Consequently, any increase or decrease in such fuel cost is generally

accompanied by an increase or decrease in related fuel revenues under the PPAs and does not have a significant impact on net income. Southern Power is responsible for the cost of fuel for generating units that are not covered under PPAs. Power from these generating units is sold into the market or sold to affiliates under the IIC.

Purchased power expenses will vary depending on demand and the availability and cost of generating resources throughout the Southern Company system and other contract resources. Load requirements are submitted to the power pool on an hourly basis and are fulfilled with the lowest cost alternative, whether that is generation owned by Southern Power Company, affiliate companies, or external parties.

In the second quarter 2015, total fuel and purchased power expenses were $127 million compared to $151 million for the corresponding period in 2014. The decrease was the result of a $58 million decrease in the average cost of fuel and purchased power primarily due to lower natural gas prices, partially offset by a $34 million net increase in the total volume of KWHs generated and purchased primarily due to increased demand resulting from lower natural gas prices.

For year-to-date 2015, total fuel and purchased power expenses were $291 million compared to $334 million for the corresponding period in 2014. The decrease was a result of a $154 million decrease in the average cost of fuel and purchased power primarily due to lower natural gas prices, partially offset by a $111 million net increase in the total volume of KWHs generated and purchased primarily due to increased demand resulting from lower natural gas prices.

Fuel

In the second quarter 2015, fuel expense was $105 million compared to $118 million for the corresponding period in 2014. The decrease was due to a 36.1% decrease associated with the average cost of natural gas per KWH generated, partially offset by a 40.6% increase associated with the volume of KWHs generated, primarily as a result of increased demand resulting from lower natural gas prices.

For year-to-date 2015 and for the corresponding period in 2014, fuel expense was $243 million. While there was no overall change, a $152 million increase in the total cost of fuel attributable to the volume of KWHs generated was offset by a $152 million decrease in the average cost of natural gas per KWH generated.

Purchased Power – Non-Affiliates and Affiliates

In the second quarter 2015, purchased power expense was $22 million compared to $33 million for the corresponding period in 2014. For year-to-date 2015, purchased power expense was $48 million compared to $91 million for the corresponding period in 2014. The decreases were primarily the result of 37.4% and 45.6% decreases in the volume of KWHs purchased in the second quarter 2015 and year-to-date 2015, respectively, primarily due to lower natural gas prices which resulted in higher use of Southern Power Company's generation resources.

Other Operations and Maintenance Expenses

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$—	—	$(1)	(0.8)

In the second quarter 2015 and for the corresponding period in 2014, other operations and maintenance expenses were $69 million. While there was no overall change, a decrease in outage expense of $10 million was offset by a $10 million increase in expenses associated with support services, transmission, and new plants placed in service in 2014 and 2015.

For year-to-date 2015, other operations and maintenance expenses were $121 million compared to $122 million for the corresponding period in 2014. The decrease was primarily due to a $17 million decrease in outage expense,

largely offset by a $16 million increase in expenses associated with support services, new plants placed in service in 2014 and 2015, and transmission.

Depreciation and Amortization

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$8	15.4	$15	14.6

In the second quarter 2015, depreciation and amortization was $60 million compared to $52 million for the corresponding period in 2014. For year-to-date 2015, depreciation and amortization was $118 million compared to $103 million for the corresponding period in 2014. The increases were primarily related to solar facilities placed in service in 2014 and 2015.

Income Taxes (Benefit)

Second Quarter 2015 vs. Second Quarter 2014		Year-to-Date 2015 vs. Year-to-Date 2014	
(change in millions)	*(% change)*	*(change in millions)*	*(% change)*
$4	133.3	$13	N/M

N/M – Not meaningful

In the second quarter 2015, income taxes were $1 million compared to an income tax benefit of $3 million for the corresponding period in 2014. For year-to-date 2015, income taxes were $13 million. The increases were primarily due to higher pre-tax earnings in 2015 and beneficial state income tax changes in 2014, partially offset by increased federal income tax benefits related to ITCs in 2015.

See Note (G) to the Condensed Financial Statements herein for additional information.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Southern Power's future earnings potential. The level of Southern Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Southern Power's competitive wholesale business. These factors include Southern Power's ability to achieve sales growth while containing costs; regulatory matters; creditworthiness of customers; total generating capacity available in Southern Power's market areas; the successful remarketing of capacity as current contracts expire; and Southern Power's ability to execute its acquisition and value creation strategy, including successfully expanding investments in renewable energy projects, and to construct generating facilities, including the impact of federal ITCs.

Other factors that could influence future earnings include weather, demand, cost of generating units within the power pool, and operational limitations. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Southern Power in Item 7 of the Form 10-K.

Environmental Matters

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Power in Item 7 of the Form 10-K for information on the development by federal and state environmental regulatory agencies of additional control strategies for emissions of air pollution from industrial sources, including electric generating facilities. Compliance with possible additional federal or state legislation or regulations related to global climate change, air quality, water quality, or other environmental and health concerns could also significantly affect Southern Power. While Southern Power's PPAs generally contain provisions that permit charging the counterparty with some of the new costs incurred as a result of changes in environmental laws and regulations, the full impact of any such regulatory or legislative changes cannot be determined at this time.

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Southern Power in Item 7 of the Form 10-K for additional information regarding the EPA's proposed regulations governing emissions during startup, shutdown, or malfunction (SSM) and the Cross State Air Pollution Rule (CSAPR).

On June 12, 2015, the EPA published a final rule requiring affected states (including Alabama, Florida, Georgia, North Carolina, and Texas) to revise or remove state implementation plan (SIP) provisions regarding excess emissions that occur during periods of SSM by no later than November 22, 2016. The ultimate impact of the final rule will depend on the outcome of any legal challenges and the development and approval of SIPs by the affected states and cannot be determined at this time.

On July 28, 2015, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion invalidating certain emissions budgets under the CSAPR Phase II emissions trading program for a number of states, including Alabama, Florida, Georgia, North Carolina, and Texas. The court's decision leaves the emissions trading program in place and remands the rule to the EPA for further action consistent with the court's decision. The court rejected all other pending challenges to the rule. The ultimate impact of this decision will depend on additional rulemaking and cannot be determined at this time.

Global Climate Issues

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" of Southern Power in Item 7 of the Form 10-K for additional information regarding the EPA's proposed regulation of CO_2 from fossil-fuel-fired electric generating units.

On August 3, 2015, the EPA released pre-publication versions of two final rules that would limit CO_2 emissions from fossil fuel-fired electric generating units. One of the final rules contains specific emission standards governing CO_2 emissions from new, modified, and reconstructed units. The other final rule 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. At the same time, the EPA also proposed a federal plan and proposed model rule that states can adopt or that would be put in place if, in response to the final guidelines, a state either does not submit a state plan or its plan is not approved by the EPA. 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. Southern Power's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through existing PPAs. However, the ultimate financial and operational impact of the final rules on Southern Power cannot be determined at this time and will depend on numerous factors including the Southern Company system's ongoing review of the final rules; the outcome of any 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; the impact of future changes in generation and emissions related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

Acquisitions

During 2015, Southern Power Company acquired or contracted to acquire the following projects in accordance with its overall growth strategy, which are included in Southern Power's capital program estimates for 2015.

Kay County Wind Facility

On February 24, 2015, Southern Power Company, through its wholly-owned subsidiary Southern Renewable Energy, Inc., entered into a purchase agreement with Kay Wind Holdings, LLC, a wholly-owned subsidiary of Apex Clean Energy Holdings, LLC, the developer of the project, to acquire all of the outstanding membership interests of Kay Wind, LLC (Kay Wind) for approximately $492 million, with potential purchase price adjustments based on

performance testing. Kay Wind is constructing and owns an approximately 299-MW wind facility in Kay County, Oklahoma. The wind facility is expected to begin commercial operation in late 2015, and the entire output of the facility is contracted under separate 20-year PPAs with Westar Energy, Inc. and Grand River Dam Authority. The completion of the acquisition is subject to Kay Wind achieving certain construction and project milestones, as well as various other customary conditions to closing, and is expected to close in the fourth quarter 2015. The ultimate outcome of this matter cannot be determined at this time. See Note 2 to the financial statements of Southern Power in Item 8 of the Form 10-K for additional information.

Lost Hills-Blackwell Solar Facilities

On April 15, 2015, Southern Power Company, through its subsidiary Southern Renewable Partnerships, LLC (SRP), acquired 100% of the class A membership interests of Lost Hills Blackwell Holdings, LLC (Lost Hills Blackwell) from a wholly-owned subsidiary of First Solar, Inc. (First Solar), the developer of the project, for approximately $74 million. Concurrently, a wholly-owned subsidiary of First Solar acquired 100% of the class B membership interests of Lost Hills Blackwell for approximately $33 million. SRP and the class B member are entitled to 51% and 49%, respectively, of all cash distributions from Lost Hills Blackwell. In addition, Southern Power Company is entitled to substantially all of the federal tax benefits with respect to the transaction. Lost Hills Blackwell constructed and owns the approximately 22-MW Lost Hills and the approximately 13-MW Blackwell solar facilities in Kern County, California. These solar facilities began commercial operation on April 17, 2015, and their entire output is contracted under PPAs, initially to the City of Roseville, California and then to Pacific Gas and Electric Company, that together extend approximately 29 years.

North Star Solar Facility

On April 30, 2015, Southern Power Company, through its subsidiary SRP, acquired 100% of the class A membership interests of NS Solar Holdings, LLC (North Star) from a wholly-owned subsidiary of First Solar, the developer of the project, for approximately $211 million. Concurrently, a wholly-owned subsidiary of First Solar acquired 100% of the class B membership interests of North Star for approximately $100 million. SRP and the class B member are entitled to 51% and 49%, respectively, of all cash distributions from North Star. In addition, Southern Power Company is entitled to substantially all of the federal tax benefits with respect to the transaction. North Star constructed and owns the approximately 61-MW North Star solar facility in Fresno County, California. The solar facility began commercial operation on June 20, 2015, and the entire output of the project is contracted under a 20-year PPA with Pacific Gas and Electric Company.

Construction Projects

In December 2014, Southern Power Company announced plans to build a solar photovoltaic facility, and during 2015, Southern Power Company acquired all the outstanding membership interests of five separate solar project development entities. The construction projects are in accordance with Southern Power's overall growth strategy and included in its capital program estimates for 2015. The total cost of construction incurred for these projects through June 30, 2015 was $188 million. The ultimate outcome of these matters cannot be determined at this time.

Southern Power Company's construction projects are detailed in the table below:

Solar Project	Seller	Nameplate Capacity	County Location in Georgia	Expected Commercial Operation Date	PPA Counterparty for Entire Plant Output	PPA Contract Period	Estimated Construction Cost	
		(MW)					*(in millions)*	
Taylor County	N/A	146	Taylor	Fourth quarter 2016	Cobb, Flint, and Sawnee Electric Membership Corporations	25 years	$260 - $280	
Decatur Parkway	TradeWind Energy, Inc.	84	Decatur	December 2015	Georgia Power[a]	25 years	$170 - $173	[b]
Decatur County	TradeWind Energy, Inc.	20	Decatur	December 2015	Georgia Power[a]	20 years	$ 45 - $47	[b]
Butler	CERSM, LLC and Community Energy, Inc.	103	Taylor	December 2016	Georgia Power[a]	30 years	$220 - $230	[b]
Pawpaw	Longview Solar, LLC	30	Taylor	December 2015	Georgia Power[a]	30 years	$ 70 - $80	[b]
Butler Solar Farm	Strata Solar Development, LLC	20	Taylor	December 2015	Georgia Power[a]	20 years	$ 42 - $48	[b]

(a) Subject to FERC approval.
(b) Includes the acquisition price of all outstanding membership interests.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information.

Power Sales Agreements

See BUSINESS – "The Southern Company System – Southern Power" in Item 1 of the Form 10-K for additional information regarding Southern Power's PPAs with investor-owned utilities, independent power purchasers, municipalities, and electric cooperatives.

Taking into account the PPAs and capacity from the acquisitions and construction projects discussed herein, together with various new PPAs relating to Southern Power's existing fleet, the coverage ratio of its available capacity for the next five years and the next 10 years has not changed materially as of June 30, 2015 from the period ended December 31, 2014.

FERC Matters

Southern Power has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional operating companies and Southern Power filed a triennial market power analysis on June 30, 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional operating companies' and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional operating companies and in some adjacent areas. To retain market-based rate authority, the FERC directed the traditional 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 operating companies and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

Other Matters

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

The ultimate outcome of such pending or potential litigation against Southern Power cannot be predicted at this time; however, for current proceedings not specifically reported in Note (B) to the Condensed Financial Statements herein or in Note 3 to the financial statements of Southern Power in Item 8 of the Form 10-K, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Power's financial statements.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Southern Power prepares its consolidated financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Southern Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Southern Power's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Southern Power in Item 7 of the Form 10-K for a complete discussion of Southern Power's critical accounting policies and estimates related to Revenue Recognition, Impairment of Long Lived Assets and Intangibles, Acquisition Accounting, Depreciation, and ITCs.

Recently Issued Accounting Standards

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers*, revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. Southern Power continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On February 18, 2015, the FASB issued Accounting Standards Update (ASU) 2015-02, *Amendments to the Consolidation Analysis*, which makes certain changes to both the variable interest model and the voting model, including changes to the identification of variable interests, the variable interest entity characteristics for a limited partnership or similar entity, and the primary beneficiary determination. This ASU is effective for fiscal years beginning after December 15, 2015. Southern Power is currently evaluating these requirements. The ultimate impact of this ASU has not yet been determined.

On April 7, 2015, the FASB issued ASU No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs.* The ASU requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. Southern Power currently reflects unamortized debt issuance costs in other deferred charges and assets – non-affiliated on its balance sheet. Upon adoption, the reclassification will not have a material impact on the results of operations, financial position, or cash flows of Southern Power.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Southern Power's financial condition remained stable at June 30, 2015. Southern Power intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit agreements as needed to meet future capital and liquidity needs. See "Sources of Capital" herein for additional information on lines of credit.

Net cash provided from operating activities totaled $251 million for the first six months of 2015, compared to $193 million for the first six months of 2014. The increase in cash provided from operating activities was primarily due to lower purchased power costs and an increase in income tax benefits received. Net cash used for investing activities totaled $570 million for the first six months of 2015 primarily due to the Lost Hills, Blackwell, and North Star acquisitions and expenditures related to the construction of new solar facilities. Net cash provided from financing activities totaled $464 million for the first six months of 2015 primarily due to the issuance of additional senior notes in May 2015. Fluctuations in cash flow from financing activities vary from period to period based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for the first six months of 2015 include a $300 million increase in plant in service, net of depreciation primarily due to the Lost Hills, Blackwell, and North Star acquisitions and a $190 million increase in CWIP primarily due to the construction of new solar facilities. Other significant changes include an increase in long-term debt of $642 million primarily as a result of the issuance of senior notes in May 2015.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Power in Item 7 of the Form 10-K for a description of Southern Power's capital requirements for its construction program, scheduled maturities of long-term debt, as well as the related interest, leases, derivative obligations, purchase commitments, and unrecognized tax benefits. Subsequent to June 30, 2015, $525 million of long-term debt was repaid at maturity. There are no other scheduled maturities of long-term debt through June 30, 2016.

The capital program is subject to periodic review and revision. These amounts include estimates for potential plant acquisitions and new construction as well as ongoing capital improvements and work to be performed under long-term service agreements. Planned expenditures for plant acquisitions may vary materially due to market opportunities and Southern Power's ability to execute its growth strategy. Capital expenditures of Southern Power are currently estimated to be approximately $1.4 billion for 2015, which includes approximately $1.3 billion for acquisitions and/or construction of new generating facilities. See Note (I) to the Condensed Financial Statements herein for additional information. Actual capital costs may vary from these estimates because of changes in factors such as business conditions; environmental statutes and regulations; FERC rules and regulations; load projections; legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital.

Sources of Capital

Southern Power plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, 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. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Southern Power in Item 7 of the Form 10-K for additional information.

Southern Power's current liabilities sometimes exceed current assets due to the use of short-term debt as a funding source, as well as cash needs, which can fluctuate significantly due to the seasonality of the business. In 2015, Southern Power has utilized the capital markets to issue additional senior notes and expects to utilize the capital

markets, bank term loans, and commercial paper markets, as the source of funds for the majority of its maturities and to meet short-term liquidity needs, including funding acquisition and construction costs.

To meet liquidity and capital resource requirements, Southern Power had at June 30, 2015 cash and cash equivalents of approximately $220 million and Southern Power Company had a committed credit facility of $500 million (Facility) expiring in 2018, of which $466 million is unused.

The Facility contains a covenant that limits the ratio of debt to capitalization (each as defined in the Facility) to a maximum of 65% and contains a cross default provision that is restricted only to the indebtedness of Southern Power. Southern Power Company is currently in compliance with all covenants in the Facility.

Proceeds from this Facility may be used for working capital and general corporate purposes as well as liquidity support for Southern Power Company's commercial paper program. Subject to applicable market conditions, Southern Power Company expects to renew or replace the Facility, as needed, prior to expiration. In connection therewith, Southern Power Company may extend the maturity date and/or increase or decrease the lending commitment thereunder. See Note 6 to the financial statements of Southern Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information.

Southern Power 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. Subsequent to June 30, 2015, commercial paper was used to partially fund the maturity of long-term debt in July 2015.

Details of short-term borrowings were as follows:

	Commercial Paper at the End of the Period		Commercial Paper During the Period(*)		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
June 30, 2015:	$ —	—%	$ 163	0.6%	$ 339

(*) Average and maximum amounts are based upon daily balances during the three-month period ended June 30, 2015.

Southern Power believes the need for working capital can be adequately met by utilizing the commercial paper program, the Facility, and operating cash flows.

Credit Rating Risk

Southern Power does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and Baa2, or BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, and energy price risk management.

The maximum potential collateral requirements under these contracts at June 30, 2015 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and Baa2	$ 9
At BBB- and/or Baa3	320
Below BBB- and/or Baa3	1,081

Included in these amounts are certain agreements that could require collateral in the event that one or more power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact Southern Power's ability to access capital markets, particularly the short-term debt market.

In addition, Southern Power has a PPA that could require collateral, but not accelerated payment, in the event of a downgrade of Southern Power Company's credit. The PPA requires credit assurances without stating a specific credit rating. The amount of collateral required would depend upon actual losses, if any, resulting from a credit downgrade.

Financing Activities

In May 2015, Southern Power Company issued $350 million aggregate principal amount of Series 2015A 1.500% Senior Notes due June 1, 2018 and $300 million aggregate principal amount of Series 2015B 2.375% Senior Notes due June 1, 2020. The proceeds were used to repay a portion of its outstanding short-term indebtedness, for other general corporate purposes, including Southern Power's growth strategy and continuous construction program, and for a portion of the subsequent repayment at maturity of $525 million aggregate principal amount of Southern Power Company's 4.875% Senior Notes on July 15, 2015.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Southern Power 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.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS
FOR
THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
ALABAMA POWER COMPANY
GEORGIA POWER COMPANY
GULF POWER COMPANY
MISSISSIPPI POWER COMPANY
SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
(UNAUDITED)

INDEX TO THE NOTES TO THE CONDENSED FINANCIAL STATEMENTS

Note		Page Number
A	Introduction	150
B	Contingencies and Regulatory Matters	152
C	Fair Value Measurements	168
D	Stockholders' Equity	173
E	Financing	175
F	Retirement Benefits	177
G	Income Taxes	180
H	Derivatives	181
I	Acquisitions	190
J	Segment and Related Information	193

INDEX TO APPLICABLE NOTES TO FINANCIAL STATEMENTS BY REGISTRANT

The following unaudited notes to the condensed financial statements are a combined presentation. The list below indicates the registrants to which each footnote applies.

Registrant	Applicable Notes
Southern Company	A, B, C, D, E, F, G, H, I, J
Alabama Power	A, B, C, E, F, G, H
Georgia Power	A, B, C, E, F, G, H
Gulf Power	A, B, C, E, F, G, H
Mississippi Power	A, B, C, E, F, G, H
Southern Power	A, B, C, D, E, G, H, I

NOTES TO THE CONDENSED FINANCIAL STATEMENTS:
(UNAUDITED)

(A) INTRODUCTION

The condensed quarterly financial statements of each registrant included herein have been prepared by such registrant, without audit, pursuant to the rules and regulations of the SEC. The Condensed Balance Sheets as of December 31, 2014 have been derived from the audited financial statements of each registrant. In the opinion of each registrant's management, the information regarding such registrant furnished herein reflects all adjustments, which, except as otherwise disclosed, are of a normal recurring nature, necessary to present fairly the results of operations for the periods ended June 30, 2015 and 2014. Certain information and footnote disclosures normally included in annual financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations, although each registrant believes that the disclosures regarding such registrant are adequate to make the information presented not misleading. Disclosures which would substantially duplicate the disclosures in the Form 10-K and details which have not changed significantly in amount or composition since the filing of the Form 10-K are generally omitted from this Quarterly Report on Form 10-Q unless specifically required by GAAP. Therefore, these Condensed Financial Statements should be read in conjunction with the financial statements and the notes thereto included in the Form 10-K. Due to the seasonal variations in the demand for energy, operating results for the periods presented are not necessarily indicative of the operating results to be expected for the full year.

Certain prior year data presented in the financial statements have been reclassified to conform to the current year presentation. These reclassifications had no impact on the results of operations, financial position, or cash flows of any registrant.

On February 6, 2015, Gulf Power announced plans to retire its coal-fired generation at Plant Smith Units 1 and 2 (357 MWs) by March 31, 2016. In March 2015, in connection with this retirement, Gulf Power reclassified the net carrying value of these units from plant in service, net of depreciation, to other utility plant, net. Gulf Power expects to recover through its rates the remaining book value of the retired units and certain costs associated with the retirements; however, recovery will be considered by the Florida PSC in future rate proceedings.

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, as well as the current period. 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

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers*, revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. The registrants continue to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On February 18, 2015, the FASB issued Accounting Standards Update (ASU) 2015-02, *Amendments to the Consolidation Analysis*, which makes certain changes to both the variable interest model and the voting model, including changes to the identification of variable interests, the variable interest entity characteristics for a limited partnership or similar entity, and the primary beneficiary determination. This ASU is effective for fiscal years beginning after December 15, 2015. Southern Power is currently evaluating these requirements. The ultimate impact of this ASU on Southern Power has not yet been determined.

On April 7, 2015, the FASB issued ASU No. 2015-03, *Interest–Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*. The ASU requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. Southern Company currently reflects unamortized debt issuance costs in unamortized debt issuance expense on its balance sheet. The traditional operating companies and Southern Power currently reflect unamortized debt issuance costs in other deferred charges and assets on their balance sheets. Upon adoption, the reclassification will not have a material impact on the results of operations, financial position, or cash flows of any registrant.

Asset Retirement Obligations

See Note 1 to the financial statements of Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power under "Asset Retirement Obligations and Other Costs of Removal" in Item 8 of the Form 10-K for additional information regarding the EPA's regulation of CCR.

On April 17, 2015, the EPA published the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule) in the Federal Register, setting October 19, 2015 as the effective date of the CCR Rule. Therefore, Alabama Power, Gulf Power, and Mississippi Power recorded new asset retirement obligations (ARO) for facilities that are subject to the CCR Rule. Georgia Power had previously recorded AROs as a result of state requirements in Georgia which closely align with the requirements of the CCR Rule. The cost estimates are based on information that was known as of June 30, 2015 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. As further analysis is performed, including evaluation of the expected timing and method of compliance and refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, the traditional operating companies expect to periodically update these estimates.

As of June 30, 2015, details of the AROs, including those related to the CCR Rule, included in Southern Company's and the traditional operating companies' Condensed Balance Sheets herein were as follows:

	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power
			(in millions)		
Balance at beginning of year	$ 2,201	$ 829	$ 1,255	$ 17	$ 48
Liabilities incurred	612	401	—	71	97
Liabilities settled	(10)	(1)	(9)	—	—
Accretion	53	23	28	—	1
Cash flow revisions	58	—	82	4	2
Balance at end of period	**$ 2,914**	**$ 1,252**	**$ 1,356**	**$ 92**	**$ 148**

The increases in liabilities incurred and cash flow revisions for the six months ended June 30, 2015 primarily relate to an increase in AROs associated with facilities impacted by the CCR Rule.

In connection with a proposed settlement related to the closure of Plant Scholz, Gulf Power may incur additional AROs associated with CCR of approximately $15 million to $35 million.

(B) CONTINGENCIES AND REGULATORY MATTERS

See Note 3 to the financial statements of the registrants in Item 8 of the Form 10-K for information relating to various lawsuits, other contingencies, and regulatory matters.

General Litigation Matters

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

The ultimate outcome of such pending or potential litigation against each registrant and any subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements of each registrant in Item 8 of the Form 10-K, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on such registrant's financial statements.

Environmental Matters

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against Alabama Power and Georgia Power alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including units co-owned by Gulf Power and Mississippi Power. These civil actions sought penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. The case against Georgia Power (including claims related to a unit co-owned by Gulf Power) has been administratively closed in the U.S. District Court for the Northern District of Georgia since 2001. The case against Alabama Power (including claims involving a unit co-owned by Mississippi Power) was partially settled in 2006 through a consent decree with the EPA, and additional claims remain pending in the U.S. District Court for the Northern District of Alabama. On June 25, 2015, the U.S. Department of Justice filed a joint stipulation between Alabama Power, the EPA, and the U.S. Department of Justice proposing to modify the 2006 consent decree to resolve all remaining claims for relief alleged in the case against Alabama Power. If approved by the U.S. District Court for the Northern District of Alabama, Alabama Power will, without admitting liability, operate subject to emission rates and a cap on certain units and requirements to use only natural gas at certain units, including a unit co-owned by Mississippi Power; retire certain units at Plants Gorgas and Barry; pay a $100,000 civil penalty; and invest $1.5 million in electric transportation infrastructure projects over three years.

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

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 properties. The traditional operating companies have each received authority from their respective state PSCs to recover approved environmental compliance costs through regulatory mechanisms. These rates are adjusted annually or as necessary within limits approved by the state PSCs.

Georgia Power's environmental remediation liability as of June 30, 2015 was $40 million. Georgia Power has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act

(CERCLA), including a site in Brunswick, Georgia on the CERCLA National Priorities List. The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional cleanup and claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites are anticipated.

Georgia Power and numerous other entities have been designated by the EPA as PRPs at the Ward Transformer Superfund site located in Raleigh, North Carolina. In 2011, the EPA issued a Unilateral Administrative Order (UAO) to Georgia Power and 22 other parties, ordering specific remedial action of certain areas at the site. Later in 2011, Georgia Power filed a response with the EPA stating it has sufficient cause to believe it is not a liable party under CERCLA. The EPA notified Georgia Power in 2011 that it is considering enforcement options against Georgia Power and other non-complying UAO recipients. If the EPA pursues enforcement actions and the court determines that a respondent failed to comply with the UAO without sufficient cause, the EPA may also seek civil penalties of up to $37,500 per day for the violation and punitive damages of up to three times the costs incurred by the EPA as a result of the party's failure to comply with the UAO.

In addition to the EPA's action at this site, Georgia Power, along with many other parties, was sued in a private action by several existing PRPs for cost recovery related to the removal action. In 2013, the U.S. District Court for the Eastern District of North Carolina Western Division ruled that Georgia Power has no liability in the private action and, on March 20, 2015, the U.S. Court of Appeals for the Fourth Circuit affirmed the lower court's ruling. Therefore, the private action is now concluded.

The ultimate outcome of these remaining matters will depend upon the success of defenses asserted, the ultimate number of PRPs participating in the cleanup, and numerous other factors and cannot be determined at this time; however, as a result of Georgia Power's regulatory treatment for environmental remediation expenses, these matters are not expected to have a material impact on Southern Company's or Georgia Power's financial statements. See Note 1 to the financial statements of Georgia Power under "Environmental Remediation Recovery" in Item 8 of the Form 10-K for additional information regarding the regulatory treatment.

Gulf Power's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $47 million as of June 30, 2015. 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 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.

In 2003, Mississippi Power and numerous other entities were designated by the Texas Commission on Environmental Quality (TCEQ) as PRPs at a site that was owned by an electric transformer company that handled Mississippi Power's transformers. The TCEQ approved the final site remediation plan in 2013 and, in March 2014, the impacted utilities, including Mississippi Power, agreed to commence remediation actions on the site. Mississippi Power's environmental remediation liability was $0.3 million as of June 30, 2015 and is expected to be recovered through the ECO Plan.

The final outcome of these matters cannot be determined at this time. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, management of Southern Company, Georgia Power, Gulf Power, and Mississippi Power does not believe that additional liabilities, if any, at these sites would be material to their respective financial statements.

Nuclear Fuel Disposal Cost Litigation

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 December 2014, the Court of Federal Claims entered a judgment in favor of Georgia Power and Alabama Power in the second spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. Georgia Power recovered approximately $18 million, based on its ownership interests, and Alabama Power recovered approximately $26 million. The judgment amounts were paid on March 19, 2015. In March 2015, Georgia Power credited the award to accounts where the original costs were charged and reduced rate base, fuel, and cost of service for the benefit of customers. The final outcome of this matter for Alabama Power cannot be determined at this time; however, no material impact on Southern Company's or Alabama Power's net income is expected as the damage amounts collected from the government are expected to be used for the benefit of customers.

In March 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 June 30, 2015 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, Alabama Power's, or Georgia Power's net income is expected.

FERC Matters

Municipal and Rural Associations Tariff

See Note 3 to the financial statements of Mississippi Power under "FERC Matters" in Item 8 of the Form 10-K for additional information regarding a settlement agreement entered into by Mississippi Power regarding the establishment of a regulatory asset for Kemper IGCC-related costs. See Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and "Integrated Coal Gasification Combined Cycle" herein for information regarding Mississippi Power's construction of the Kemper IGCC.

On March 31, 2015, Mississippi Power reached a settlement agreement with its wholesale customers and filed a request with the FERC to forgo the Municipal and Rural Associations cost-based electric tariff increase reflected in the filing by, among other things, increasing the accrual of AFUDC in lieu of including CWIP in rate base. The settlement agreement, which was accepted by the FERC on May 13, 2015, provides that the additional accrual of AFUDC was effective April 1, 2015. The additional resulting AFUDC is projected to be approximately $11 million annually, of which $8 million relates to the Kemper IGCC. In addition, a settlement agreement entered into in 2014 and approved by the FERC allowed for an adjustment to the wholesale revenue requirement in the event the Kemper IGCC, or any substantial portion thereof, was placed in service before or after December 1, 2014. A regulatory asset account was recorded as a result of a portion of the Kemper IGCC being placed in service prior to the projected date. The March 31, 2015 settlement agreement provides that the regulatory asset will be amortized over nine months, beginning April 1, 2015.

Market-Based Rate Authority

The traditional 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 operating companies and Southern Power filed a triennial market power analysis on June 30, 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional operating companies' and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional operating companies and in some adjacent areas. To retain market-based rate authority, the FERC directed the traditional 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 operating companies and Southern Power filed a request

for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

Alabama Power

See Note 3 to the financial statements of Southern Company and Alabama Power under "Retail Regulatory Matters – Alabama Power" and "Retail Regulatory Matters," respectively, in Item 8 of the Form 10-K for additional information regarding Alabama Power's recovery of retail costs through various regulatory clauses and accounting orders. The recovery balance of each regulatory clause follows:

Regulatory Clause	Balance Sheet Line Item	June 30, 2015	December 31, 2014
		(in millions)	
Rate CNP Compliance – Under*	Deferred under recovered regulatory clause revenues	$ 25	$ 2
	Under recovered regulatory clause revenues, current	29	47
Rate CNP PPA – Under	Deferred under recovered regulatory clause revenues	72	29
	Under recovered regulatory clause revenues, current	—	27
Retail Energy Cost Recovery – Over	Deferred over recovered regulatory clause revenues	72	47
Natural Disaster Reserve	Other regulatory liabilities, deferred	81	84

* Formerly Known As Rate CNP Environmental

Rate CNP

See Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Alabama Power – Rate CNP" and " – Non-Environmental Federal Mandated Costs Accounting Order" and of Alabama Power under "Retail Regulatory Matters – Rate CNP" and " – Non-Environmental Federal Mandated Costs Accounting Order" in Item 8 of the Form 10-K for additional information regarding Alabama Power's development of a revised cost recovery mechanism and the normal purchases and normal sales (NPNS) exception for wind PPAs.

On March 3, 2015, the Alabama PSC approved a modification to Rate CNP Environmental to include compliance costs for both environmental and non-environmental mandates. The recoverable non-environmental compliance costs result from laws, regulations, and other mandates directed at the utility industry involving the security, reliability, safety, sustainability, or similar considerations impacting Alabama Power's facilities or operations. This modification to Rate CNP Environmental was effective March 20, 2015 with the revised rate now defined as Rate CNP Compliance. Alabama Power incurred $30 million of non-environmental compliance costs during the first six months of 2015 and will be limited to recovery of $50 million for the year. Customer rates will not be impacted before January 2016; therefore, the modification will increase the under recovered position for Rate CNP Compliance during 2015.

In April 2015, the FASB proposed new accounting guidance to allow the NPNS exception for physical forward transactions in nodal energy markets, consistent with the manner in which Alabama Power currently accounts for its two wind PPAs. On July 9, 2015, the FASB ratified the consensus reached by the Emerging Issues Task Force to allow the exception in such cases and voted to issue a final accounting standard.

Environmental Accounting Order

In April 2015, as part of its environmental compliance strategy, Alabama Power retired Plant Gorgas Units 6 and 7. These units represented 200 MWs of Alabama Power's approximately 12,200 MWs of generating capacity. 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. No later than April 2016, Alabama Power expects to cease using coal at Plant Greene County Units 1 and 2 (300 MWs) and begin operating those units solely on natural gas. Subject to the final approval of the New Source Review stipulation, Alabama Power will also

retire Plant Barry Unit 3 (225 MWs) which is currently unavailable for generation. See "Environmental Matters – New Source Review Actions" herein for additional information regarding the NSR actions.

In accordance with an 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 over the remaining useful lives, as established prior to the decision for retirement. As a result, these decisions will not have a significant impact on Southern Company's or Alabama Power's financial statements.

Georgia Power

Integrated Resource Plan

See Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters – Georgia Power – Integrated Resource Plans" and "Retail Regulatory Matters – Integrated Resource Plans," respectively, in Item 8 of the Form 10-K for additional information.

To comply with the April 16, 2015 effective date of the MATS rule, Plant Branch Units 1, 3, and 4 (1,266 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) were retired on April 15, 2015. In addition, operations were discontinued at Plant Mitchell Unit 3 (155 MWs) and its decertification will be requested in connection with the triennial Integrated Resource Plan in 2016. The switch to natural gas as the primary fuel is complete at Plant Yates Units 7 and 6 and the units were returned to service on May 4, 2015 and June 27, 2015, respectively.

Fuel Cost Recovery

See Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters – Georgia Power – Fuel Cost Recovery" and "Retail Regulatory Matters – Fuel Cost Recovery," respectively, in Item 8 of the Form 10-K for additional information.

As of June 30, 2015 and December 31, 2014, Georgia Power's under recovered fuel balance totaled $106 million and $199 million, respectively. For June 30, 2015 and December 31, 2014, the balance is included in current assets and current assets and other deferred charges and assets, respectively, on Southern Company's and Georgia Power's Condensed Balance Sheets herein. Georgia Power expects to file its next fuel case in September 2015. The ultimate outcome of this matter cannot be determined at this time.

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

Nuclear Construction

See Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Retail Regulatory Matters – Nuclear Construction," respectively, in Item 8 of the Form 10-K for additional information regarding Georgia Power's construction of Plant Vogtle Units 3 and 4, Vogtle Construction Monitoring (VCM) reports, and pending litigation.

In 2008, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into an agreement (Vogtle 3 and 4 Agreement) with the Contractor, pursuant to which the Contractor agreed to design, engineer, procure, construct, and test Plant Vogtle Units 3 and 4. Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price that is 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. The Contractor's liability to the Vogtle Owners for schedule and performance liquidated damages and warranty claims is subject to a cap. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which have not 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%.

Certain payment obligations of Westinghouse and CB&I Stone & Webster, Inc. (formerly known as Stone & Webster, Inc.) under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group Inc. (a subsidiary of Chicago Bridge & Iron Company, N.V.), respectively. 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. The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay certain termination costs. 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 2009, the NRC issued an Early Site Permit and Limited Work Authorization which allowed limited work to begin on Plant Vogtle Units 3 and 4. The NRC certified the Westinghouse Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, in late 2011, and issued combined construction and operating licenses (COLs) in early 2012. Receipt of the COLs allowed full construction to begin. 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 are expected as construction proceeds.

In 2012, the Vogtle Owners and the Contractor began negotiations regarding the costs associated with design changes to the DCD and the delays in the timing of approval of the DCD and issuance of the COLs, including the assertion by the Contractor that the Vogtle Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. Also in 2012, Georgia Power and the other Vogtle Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Vogtle Owners are not responsible for these costs. In 2012, the Contractor also filed suit against Georgia Power and the other Vogtle Owners in the U.S. District Court for the District of Columbia alleging the Vogtle Owners are responsible for these costs. In 2013, the U.S. District Court for the District of Columbia dismissed the Contractor's suit, ruling that the proper venue is the U.S. District Court for the Southern District of Georgia. On March 10, 2015, the U.S. Court of Appeals for the District of Columbia Circuit affirmed the District Court's decision. The portion of additional costs claimed by the Contractor in its initial complaint that would be attributable to Georgia Power (based on Georgia Power's ownership interest) is approximately $425 million in 2008 dollars (approximately $591 million in 2015 dollars). The Contractor also asserted it is entitled to extensions of the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. In May 2014, the Contractor filed an amended counterclaim to the suit pending in the U.S. District Court for the Southern District of Georgia alleging that (i) the design changes to the DCD imposed by the NRC delayed module production and the impacts to the Contractor are recoverable by the Contractor under the Vogtle 3 and 4 Agreement and (ii) the changes to the basemat rebar design required by the NRC caused additional costs and delays recoverable by the Contractor under the Vogtle 3 and 4 Agreement. The Contractor did not specify in its amended counterclaim the amounts relating to these new allegations; however, the Contractor subsequently asserted estimated minimum damages related to the amended counterclaim (based on Georgia Power's ownership interest) of approximately $113 million in 2014 dollars (approximately $118 million in 2015 dollars). In June 2015, the Contractor updated its estimated damages under the initial complaint and the amended counterclaim to an aggregate (based on Georgia Power's ownership interest) of approximately $714 million (in 2015 dollars). The Contractor may from time to time continue to assert that it is entitled to additional payments with respect to these allegations, any of which could be substantial. Georgia Power has not agreed to the proposed cost or to any changes to the guaranteed substantial completion dates or that the Vogtle Owners have any responsibility for costs related to these issues. Litigation is ongoing and Georgia Power intends to vigorously defend the positions of the Vogtle Owners. Georgia Power also expects negotiations with the Contractor to continue with respect to cost and schedule. During such negotiations the parties may reach a mutually acceptable compromise of their positions.

Georgia Power is required to file semi-annual VCM reports with the Georgia PSC by February 28 and August 31 each year. If the projected certified construction capital costs to be borne by Georgia Power increase by 5% or the projected in-service dates are significantly extended, Georgia Power is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. Georgia Power's eighth VCM report filed in 2013 requested an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 from $4.4 billion to $4.8 billion and to extend the estimated in-service dates to the fourth quarter 2017 and the fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively. In 2013, the Georgia PSC approved a stipulation (2013 Stipulation) entered into by 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. The Georgia PSC has approved eleven VCM reports covering the periods through June 30, 2014, including construction capital costs incurred, which through that date totaled $2.8 billion.

On January 29, 2015, Georgia Power announced it was notified by the Contractor of the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4, which would incrementally delay the previously disclosed estimated in-service dates by 18 months (from the fourth quarter of 2017 to the second quarter of 2019 for Unit 3 and from the fourth quarter of 2018 to the second quarter of 2020 for Unit 4).

Georgia Power believes that, pursuant to the Vogtle 3 and 4 Agreement, the Contractor is responsible for the Contractor's costs related to the Contractor's delay (including any related construction and mitigation costs, which could be material) and that the Vogtle Owners are entitled to recover liquidated damages for the Contractor's delay beyond the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. Consistent with the Contractor's position in the pending litigation described above, Georgia Power expects the Contractor to contest any claims for liquidated damages and to assert that the Vogtle Owners are responsible for additional costs related to the Contractor's delay.

On February 27, 2015, Georgia Power filed its twelfth VCM report with the Georgia PSC covering the period from July 1 through December 31, 2014, which requested approval for an additional $0.2 billion of construction capital costs incurred during that period. The twelfth VCM report also reflected the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4 as well as additional estimated owner-related costs, which include approximately $10 million per month expected to result from the Contractor's proposed 18-month delay, including property taxes, oversight costs, compliance costs, and other operational readiness costs. No Contractor costs related to the Contractor's proposed 18-month delay were included in the twelfth VCM report. Additionally, while Georgia Power has not agreed to any change to the guaranteed substantial completion dates, the twelfth VCM report included a requested amendment (Requested Amendment) to the Plant Vogtle Units 3 and 4 certificate to reflect the Contractor's revised forecast, to include the estimated owner's costs associated with the proposed 18-month Contractor delay, and to increase the estimated total in-service capital cost of Plant Vogtle Units 3 and 4 to $5.0 billion.

Georgia Power will continue to incur financing costs of approximately $30 million per month until Plant Vogtle Units 3 and 4 are placed in service. The twelfth VCM report estimated financing costs during the construction period to total approximately $2.5 billion.

On April 15, 2015, the Georgia PSC issued a procedural order in connection with the twelfth VCM report. Pursuant to this order, the Georgia PSC deemed the Requested Amendment unnecessary and withdrawn until the completion of construction of Plant Vogtle Unit 3 consistent with the 2013 Stipulation. The Georgia PSC recognized that the certified cost and the 2013 Stipulation do not constitute a cost recovery cap. In accordance with the Georgia Integrated Resource Planning Act, any costs incurred by Georgia Power in excess of the certified amount will be included in rate base, provided Georgia Power shows the costs to be reasonable and prudent. Financing costs up to the certified amount will be collected through the NCCR tariff until the units are placed in service, while financing costs on any construction-related costs in excess of the $4.4 billion certified amount are expected to be recovered through AFUDC.

Processes are in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, 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 issues are expected to 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.

As construction continues, the risk remains that ongoing challenges with Contractor performance including additional challenges in its fabrication, assembly, delivery, and installation of the shield building and structural modules, delays in the receipt of the remaining permits necessary for the operation of Plant Vogtle Units 3 and 4, or other issues could arise and may further impact project schedule and cost. In addition, the IRS allocated production tax credits to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021.

Additional claims by the Contractor or Georgia Power (on behalf of the Vogtle Owners) are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement, but also may be resolved through litigation.

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

Gulf Power

Retail Base Rate Case

See Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Retail Base Rate Case" in Item 8 of the Form 10-K for additional information.

In December 2013, the Florida PSC approved a settlement agreement that provides Gulf Power may reduce depreciation expense and record a regulatory asset up to $62.5 million between January 2014 and June 2017. In any given month, such depreciation expense reduction may not exceed the amount necessary for the ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized retail ROE range then in effect. Gulf Power recognized a $19.6 million reduction in depreciation expense in the first six months of 2015.

Cost Recovery Clauses

See Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Cost Recovery Clauses" in Item 8 of the Form 10-K for additional information regarding Gulf Power's recovery of retail costs through various regulatory clauses and accounting orders. Gulf Power has four regulatory clauses which are approved by the Florida PSC. The recovery balance of each regulatory clause follows:

Recovery Clause	Balance Sheet Location	June 30, 2015	December 31, 2014
		(in millions)	
Fuel Cost Recovery – Under	Under recovered regulatory clause revenues	$ 24	$ 40
Purchased Power Capacity Recovery – Under	Under recovered regulatory clause revenues	2	—
Environmental Cost Recovery – Under	Under recovered regulatory clause revenues	7	10
Energy Conservation Cost Recovery – Under	Under recovered regulatory clause revenues	—	3

Mississippi Power

2015 Rate Case

On May 15, 2015 and July 10, 2015, Mississippi Power filed alternative rate proposals related to recovery of Kemper IGCC-related costs with the Mississippi PSC. See "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2015 Rate Case" herein for additional information.

Performance Evaluation Plan

See Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Performance Evaluation Plan" in Item 8 of the Form 10-K for additional information regarding Mississippi Power's base rates.

On March 17, 2015, Mississippi Power submitted its annual PEP lookback filing for 2014, which indicated no surcharge or refund. On March 26, 2015, the Mississippi PSC suspended the filing to allow it more time for review. The ultimate outcome of this matter cannot be determined at this time.

System Restoration Rider

See Note 1 to the financial statements of Mississippi Power under "Provision for Property Damage" in Item 8 of the Form 10-K for additional information.

On February 2, 2015, Mississippi Power submitted its 2015 System Restoration Rider (SRR) rate filing with the Mississippi PSC, which proposed that the 2015 SRR rate remain level at zero and Mississippi Power be allowed to accrue $3 million to the property damage reserve in 2015. On March 3, 2015, the Mississippi PSC suspended the filing to allow it more time for review. The ultimate outcome of this matter cannot be determined at this time.

Environmental Compliance Overview Plan

See Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Environmental Compliance Overview Plan" and "Other Matters – Sierra Club Settlement Agreement" in Item 8 of the Form 10-K for information on Mississippi Power's annual environmental filing with the Mississippi PSC and information on Plant Watson Units 4 and 5.

In 2012, the Mississippi PSC approved Mississippi Power's request for a CPCN to construct scrubbers on Plant Daniel Units 1 and 2, which are scheduled to be placed in service in September and November 2015, respectively. These units are jointly owned by Mississippi Power and Gulf Power, with 50% ownership each. The estimated total cost of the project is approximately $660 million, with Mississippi Power's portion being $330 million, excluding AFUDC. Mississippi Power's portion of the cost is expected to be recovered through the ECO Plan following the scheduled completion of the project. As of June 30, 2015, total project expenditures were $604 million, of which Mississippi Power's portion was $308 million, excluding AFUDC of $27 million.

On February 25, 2015, Mississippi Power submitted its annual ECO filing for 2015, which indicated an annual increase in revenues of approximately $8 million. On February 27, 2015, the Mississippi PSC suspended the filing to allow it more time to review. The ultimate outcome of this matter cannot be determined at this time.

On April 16, 2015, the assets that supported coal generation at Plant Watson Units 4 and 5 were retired. The remaining net book value of these two units was approximately $32 million excluding the reserve for cost of removal and has been reclassified to other regulatory assets, deferred, on Mississippi Power's Condensed Balance Sheet herein in accordance with an accounting order from the Mississippi PSC. Mississippi Power expects to recover through its rates the remaining book value of the retired assets and certain costs, including unusable inventory, associated with the retirements; however, the ultimate method and timing of recovery will be considered by the Mississippi PSC in future rate proceedings.

Fuel Cost Recovery

See Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Fuel Cost Recovery" in Item 8 of the Form 10-K for information regarding Mississippi Power's fuel cost recovery.

At June 30, 2015, the amount of over-recovered retail fuel costs included on Mississippi Power's Condensed Balance Sheet herein was $24 million compared to under-recovered retail fuel costs of $2 million at December 31, 2014.

Ad Valorem Tax Adjustment

See Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Ad Valorem Tax Adjustment" in Item 8 of the Form 10-K for additional information.

On April 23, 2015, Mississippi Power filed its annual ad valorem tax adjustment factor filing for 2015, which requested an annual rate decrease of 0.35%, or $2 million in annual retail revenues, primarily due to a decrease in average millage rates. On May 26, 2015 the Mississippi PSC suspended the filing to allow it more time to review. The ultimate outcome of this matter cannot be determined at this time.

Integrated Coal Gasification Combined Cycle

See Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K for information regarding Mississippi Power's construction of the Kemper IGCC.

Kemper IGCC Overview

Construction of Mississippi Power's Kemper IGCC is nearing completion and start-up activities will continue until the Kemper IGCC is placed in service. The Kemper IGCC will utilize an IGCC technology with an output capacity of 582 MWs. The Kemper IGCC will be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by Mississippi Power and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation in 2013. In connection with the Kemper IGCC, Mississippi Power constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the planned 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 (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 using natural gas in August 2014 and continues to focus on completing the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, for which the in-service date is currently expected to occur in the first half of 2016. Recovery of the Kemper IGCC costs subject to the cost cap and 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) remains subject to review and approval by the Mississippi PSC. Mississippi Power's Kemper IGCC 2010 project estimate, current cost estimate (which includes the impacts of the Mississippi Supreme Court's (Court) decision), and actual costs incurred as of June 30, 2015, as adjusted for the Court's decision, are as follows:

Cost Category	2010 Project Estimate[f]	Current Estimate	Actual Costs at June 30, 2015
		(in billions)	
Plant Subject to Cost Cap[a]	$ 2.40	$ 4.96	**$ 4.51**
Lignite Mine and Equipment	0.21	0.23	**0.23**
CO_2 Pipeline Facilities	0.14	0.11	**0.11**
AFUDC[b][e]	0.17	0.62	**0.52**
Combined Cycle and Related Assets Placed in Service – Incremental[d]	—	0.02	**—**
General Exceptions	0.05	0.10	**0.08**
Deferred Costs[c][e]	—	0.19	**0.15**
Total Kemper IGCC[a][c]	$ 2.97	$ 6.23	**$ 5.60**

(a) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, net of the DOE Grants and excluding the Cost Cap Exceptions. The Current Estimate and 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" for additional information. The Current Estimate and Actual Costs include the 15% undivided interest in the Kemper IGCC that was previously projected to be purchased by SMEPA. On May 20, 2015, SMEPA notified Mississippi Power of its termination of the asset purchase agreement (APA) and requested the return of a total of $275 million of deposits, which was returned with accrued interest on June 3, 2015.

(b) Mississippi Power's original estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC in 2012 as described in "Rate Recovery of Kemper IGCC Costs." The current estimate includes an approximately $11 million decrease in AFUDC due to a decrease in AFUDC rates resulting from an increase in short-term debt, partially offset by an $8 million increase in AFUDC related to a settlement agreement with the wholesale customers for cost-based rates under FERC's jurisdiction. See "FERC Matters" herein for additional information.

(c) Amounts in the Current Estimate reflect estimated costs through March 31, 2016.

(d) Incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service in August 2014, net of costs related to energy sales. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" for additional information.

(e) The 2012 MPSC CPCN Order approved deferral of non-capital Kemper IGCC-related costs during construction as described in "Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities."

(f) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities which was approved in 2011 by the Mississippi PSC.

Of the total costs, including post-in-service costs for the lignite mine, incurred as of June 30, 2015, $3.42 billion was included in property, plant, and equipment (which is net of the DOE Grants and estimated probable losses of $2.08 billion), $2 million in other property and investments, $58 million in fossil fuel stock, $41 million in materials and supplies, $198 million in other regulatory assets, $16 million in other deferred charges and assets, and $24 million in AROs in the balance sheet, with $1 million previously expensed.

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 DOE Grants and excluding the Cost Cap Exceptions. Mississippi Power recorded pre-tax charges to income for revisions to the cost estimate of $23 million ($14 million after tax) in the second quarter 2015 and $9 million ($6 million after tax) in the first quarter 2015. These amounts are in addition to charges totaling $868 million ($536 million after tax), $1.10 billion ($681 million after tax), and $78 million ($48 million after tax) in 2014, 2013, and 2012, respectively. Southern Company recorded pre-tax charges to income for revisions to the cost estimate of $868 million ($536 million after tax) and $1.2 billion ($729 million after tax) in 2014 and 2013, respectively. The increases to the cost estimate in the first and second quarters of 2015 primarily reflected costs for increased efforts related to equipment rework, scope modifications, and the related additional labor costs in support of start-up and operational readiness activities. The current estimate includes costs through March 31, 2016. Any further extension of the in-service date is currently estimated to result in additional base costs of approximately $25 million to $30 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. Any further extension of the in-service date with respect to the Kemper IGCC 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 $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees, which are being deferred as regulatory assets and are estimated to total approximately $7 million per month.

Any further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (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). In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in Southern Company's statements of income and Mississippi Power's statements of operations and these changes could be material.

Rate Recovery of Kemper IGCC Costs

The ultimate outcome of the rate recovery matters discussed herein, including the resolution of legal challenges, determinations of prudency, and the specific manner of recovery of prudently-incurred costs, cannot be determined at this time, but could have a material impact on Southern Company's and Mississippi Power's results of operations, financial condition, and liquidity.

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 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 evaluation of the 2015 Rate Case and any alternative 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 Southern Company's or Mississippi Power's financial statements.

2013 Settlement Agreement

In January 2013, Mississippi Power entered into a settlement agreement with the Mississippi PSC that, among other things, established 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. The 2013 Settlement Agreement also allowed Mississippi Power to secure alternate financing for costs not otherwise recovered in any Mississippi PSC rate proceedings contemplated by the 2013 Settlement Agreement. The Court found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. See "2015 Mississippi Supreme Court Decision" herein for additional information.

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's

intent under the 2013 Settlement Agreement was to securitize (1) prudently-incurred costs in excess of the certificated cost estimate and up to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, (2) accrued AFUDC, and (3) other prudently-incurred costs, which include carrying costs from the estimated in-service date until securitization is finalized and other costs not included in Mississippi Power's 2013 revision to the proposed rate recovery plan filed with the Mississippi PSC for the Kemper IGCC for cost recovery through 2020 (2013 Rate Mitigation Plan) as approved by the Mississippi PSC. The Court's decision did not impact Mississippi Power's ability to utilize alternate financing through securitization, the 2012 MPSC CPCN Order, or the February 2013 legislation. See "2015 Mississippi Supreme Court Decision" herein for additional information.

2013 MPSC Rate Order

Consistent with the terms of the 2013 Settlement Agreement, 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. 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 the in-service date. Mississippi Power will not record AFUDC on any additional costs of the Kemper IGCC that exceed the $2.88 billion cost cap, except for Cost Cap Exception amounts. Mississippi Power will continue to record AFUDC through the in-service date until directed to do otherwise by the Mississippi PSC.

In August 2014, Mississippi Power provided an analysis of the costs and benefits of placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service, including the expected accounting treatment for costs and revenues associated with the operation of the combined cycle as well as the treatment of revenues collected under the 2013 MPSC Rate Order. See "2015 Mississippi Supreme Court Decision" for additional information regarding the decision of the Court which discontinues the collection of rates under the 2013 MPSC Rate Order and requires the refund of all amounts previously collected.

In addition, Mississippi Power's August 2014 filing with the Mississippi PSC requested confirmation of Mississippi Power's accounting treatment by the Mississippi PSC of the continued accrual of AFUDC through the in-service date of the remainder of the Kemper IGCC. See "Regulatory Assets and Liabilities" for additional information. Any action by the Mississippi PSC that is inconsistent with the treatment requested by Mississippi Power could have a material impact on the results of operations, financial condition, and liquidity of Southern Company and Mississippi Power.

2015 Mississippi Supreme Court Decision

On February 12, 2015, the Court issued its decision in the legal challenge to the 2013 MPSC Rate Order. 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 March 12, 2015, Mississippi Power and the Mississippi PSC each filed motions for rehearing, both of which were denied on June 11, 2015. The Court's ruling remanded the matter to the Mississippi PSC to (1) fix by order the rates that were in existence prior to the 2013 MPSC Rate Order, (2) fix no rate increases until the Mississippi PSC is in compliance with the Court's ruling, and (3) enter an order refunding amounts collected under the 2013 MPSC Rate Order. Through June 30, 2015, Mississippi Power had collected $331 million through rates under the 2013 MPSC Rate Order and had accrued $22 million in associated carrying costs. On July 7, 2015, the Mississippi PSC ordered that the Mirror CWIP rate be terminated effective July 20, 2015. Mississippi Power submitted a refund plan to the Mississippi PSC on July 21, 2015, which proposed two alternative refund plans for the Mississippi PSC's consideration: (1) bill credit with check option; or (2) check-only option. Hearings on the refund plan are scheduled to be held on August 6, 2015.

2015 Rate Case

As a result of the 2015 Mississippi Supreme Court decision and the Mirror CWIP refund, the 2013 Rate Mitigation Plan is no longer viable. See "2015 Mississippi Supreme Court Decision" herein for additional information. On May 15, 2015, Mississippi Power sought alternate rate recovery and filed a rate case (2015 Rate Case) with the Mississippi PSC. This filing included three alternative rate proposals requesting an increase in retail rates and charges in connection with the Kemper IGCC: (i) a traditional rate case, (ii) a rate mitigation plan fixing rates through 2017 (RMP 2017), and (iii) a rate mitigation plan fixing rates through 2019 (RMP 2019). Under the traditional proposal, rates would increase above May 2015 levels by approximately 11.8%, or $114 million annually, effective June 1, 2015, and would be projected to increase approximately an additional 12.0%, or $120 million annually, effective June 1, 2016. The traditional proposal assumes termination of the Mirror CWIP rate and the refund of the Mirror CWIP regulatory liability over the period from May 2015 through May 2017. RMP 2017 presents revenue requirements calculated consistent with a rate mitigation plan authorized by Mississippi state law that would mitigate the Kemper IGCC's initial retail revenue impact over two years (June 1, 2015 through May 31, 2017). Under RMP 2017, rates would increase above May 2015 levels by approximately 2.6%, or $25 million annually, effective June 1, 2015, and approximately an additional 19.0%, or $197 million annually, effective June 1, 2016. This proposal assumes termination of the Mirror CWIP rate and the refund of the Mirror CWIP regulatory liability over the period from May 2015 through May 2017. In light of the Mississippi PSC's July 7, 2015 order, RMP 2019 is no longer viable as originally proposed by Mississippi Power.

On July 10, 2015, Mississippi Power filed a supplemental filing including a request for interim rates (the Supplemental Notice) with the Mississippi PSC in response to the July 7, 2015 order of the Mississippi PSC. The Supplemental Notice presents an additional alternative rate proposal (In-Service Asset Proposal) for consideration by the Mississippi PSC. The In-Service Asset Proposal is based upon the test period of June 2015 to May 2016, is 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, and is designed to collect approximately $159 million annually. The Supplemental Notice requests that the In-Service Asset Proposal be implemented immediately as interim rates, subject to refund, until such time as the Mississippi PSC renders a final decision on the In-Service Asset Proposal and requests that the Mississippi PSC establish a scheduling order for consideration of permanent rates under the In-Service Asset Proposal. Evidentiary hearings on the interim rate relief are scheduled to be held on August 6, 2015.

The revenue requirements set forth in the alternative rate proposals exclude the costs of the Kemper IGCC related to the 15% undivided interest that was previously projected to be purchased by SMEPA. See "Termination of Proposed Sale of Undivided Interest to SMEPA" herein for additional information.

If the Mississippi PSC does not act on the Supplemental Notice or the 2015 Rate Case within 120 days of the Supplemental Notice filing, Mississippi Power expects to put one of the three viable alternative rate proposals into effect as temporary rates under bond and subject to refund pursuant to Mississippi state law.

Mississippi Power also expects to seek additional rate relief to address recovery of the remaining Kemper IGCC assets. In addition to current estimated costs at June 30, 2015 of $6.23 billion, Mississippi Power anticipates that it will incur additional costs after the Kemper IGCC in-service date until the Kemper IGCC cost recovery approach is finalized. These costs include, but are not limited to, regulatory costs and additional carrying costs which could be material. Recovery of these costs would be subject to approval by the Mississippi PSC.

Prudence Reviews

The Mississippi PSC's review of Kemper IGCC costs is ongoing. In August 2014, the Mississippi PSC ordered that a consolidated prudence determination of all Kemper IGCC costs be completed after the entire project has been placed in service and has demonstrated availability for a reasonable period of time as determined by the Mississippi PSC and the Mississippi Public Utilities Staff (MPUS). The Mississippi PSC has encouraged the parties to work in good faith to settle contested issues and Mississippi Power is working to reach a mutually acceptable resolution. On July 10, 2015, Mississippi Power submitted the Supplemental Notice to the Mississippi PSC. The Supplemental

Notice requests that the Mississippi PSC establish a scheduling order for review of the In-Service Asset Proposal. Mississippi Power expects the Mississippi PSC to address the In-Service Asset Proposal before the end of 2015, although Mississippi Power believes that such a prudence finding is not required for interim rate relief to be granted. See "2015 Mississippi Supreme Court Decision" and "2015 Rate Case" 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. As of June 30, 2015, the regulatory asset balance associated with the Kemper IGCC was $198 million. The projected balance at March 31, 2016 is estimated to total approximately $276 million. The amortization period for any such costs approved for recovery remains subject to approval by the Mississippi PSC.

See "2015 Mississippi Supreme Court Decision" herein for additional information related to the July 7, 2015 Mississippi PSC order terminating the Mirror CWIP rate and requiring refund of collections under Mirror CWIP.

See Note 1 to the financial statements of Southern Company and Mississippi Power under "Regulatory Assets and Liabilities" in Item 8 of the Form 10-K for additional information.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, Mississippi Power will own 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. See Note 1 to the financial statements of Mississippi Power under "Asset Retirement Obligations and Other Costs of Removal" and "Variable Interest Entities" in Item 8 of the Form 10-K for additional information.

In addition, Mississippi Power 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 has entered into agreements with Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tengrys, LLC, pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC. The agreements with Denbury and Treetop provide termination rights as Mississippi Power has not satisfied its contractual obligation to deliver captured CO_2 by May 11, 2015. Since May 11, 2015, Mississippi Power has been engaged in ongoing discussions with its off-takers regarding the status of the CO_2 delivery schedule as well as other issues related to the respective agreements. As a result of discussions with Treetop, on August 3, 2015, Mississippi Power agreed to amend certain provisions of their agreement that do not

affect pricing or minimum purchase quantities. Any termination or material modification of these agreements could result in a material reduction in future chemical product sales revenues and could have a material financial impact on Mississippi Power to the extent Mississippi Power is not able to enter into other similar contractual arrangements.

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

Termination of Proposed Sale of Undivided Interest to SMEPA

In 2010 and as amended in 2012, Mississippi Power and SMEPA entered into an APA whereby SMEPA agreed to purchase a 15% undivided interest in the Kemper IGCC. On May 20, 2015, SMEPA notified Mississippi Power of its termination of the APA between Mississippi Power and SMEPA. Mississippi Power previously received a total of $275 million of deposits from SMEPA that were required to be returned to SMEPA with interest in connection with the termination of the APA. On June 3, 2015, Southern Company, pursuant to its guarantee obligation, returned approximately $301 million to SMEPA. Subsequently, Mississippi Power issued an 18-month promissory note in the aggregate principal amount of approximately $301 million to Southern Company.

Investment Tax Credits

The IRS allocated $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to Mississippi Power in connection with the Kemper IGCC. Through June 30, 2015, Mississippi Power had recorded tax benefits totaling $276 million for the Phase II credits, of which approximately $242 million had been utilized through that date. These credits will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC and are dependent upon meeting the IRS certification requirements, including an in-service date no later than April 19, 2016 and 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. Mississippi Power currently expects to place the Kemper IGCC in service in the first half of 2016. The ultimate outcome of this matter cannot be determined at this time.

Section 174 Research and Experimental Deduction

Southern Company, on behalf of Mississippi Power, reflected deductions for research and experimental (R&E) expenditures related to the Kemper IGCC in its federal income tax calculations for 2013 and 2014. In May 2015, Southern Company amended its 2008 through 2013 federal income tax returns to include deductions for Kemper IGCC-related R&E expenditures. Due to the uncertainty related to this tax position, Southern Company and Mississippi Power had unrecognized tax benefits associated with these R&E deductions totaling approximately $390 million as of June 30, 2015. See Note 5 to the financial statements of Southern Company and Mississippi Power under "Unrecognized Tax Benefits" in Item 8 of the Form 10-K and Note (G) herein under "Unrecognized Tax Benefits – Section 174 Research and Experimental Deduction" for additional information. The ultimate outcome of this tax matter cannot be determined at this time.

(C) FAIR VALUE MEASUREMENTS

As of June 30, 2015, assets and liabilities measured at fair value on a recurring basis during the period, together with the associated level of the fair value hierarchy, were as follows:

	Fair Value Measurements Using			
As of June 30, 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)		
Southern Company				
Assets:				
Energy-related derivatives	$ —	$ 5	$ —	$ 5
Interest rate derivatives	—	11	—	11
Nuclear decommissioning trusts[a]	677	887	7	1,571
Cash equivalents	533	—	—	533
Other investments	9	—	1	10
Total	$ 1,219	$ 903	$ 8	$ 2,130
Liabilities:				
Energy-related derivatives	$ —	$ 180	$ —	$ 180
Interest rate derivatives	—	14	—	14
Total	$ —	$ 194	$ —	$ 194
Alabama Power				
Assets:				
Energy-related derivatives	$ —	$ 2	$ —	$ 2
Nuclear decommissioning trusts[b]				
Domestic equity	381	78	—	459
Foreign equity	51	50	—	101
U.S. Treasury and government agency securities	—	36	—	36
Corporate bonds	10	121	—	131
Mortgage and asset backed securities	—	17	—	17
Other	—	6	7	13
Cash equivalents	81	—	—	81
Total	$ 523	$ 310	$ 7	$ 840
Liabilities:				
Energy-related derivatives	$ —	$ 48	$ —	$ 48
Interest rate derivatives	—	7	—	7
Total	$ —	$ 55	$ —	$ 55

As of June 30, 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)	Total
		(in millions)		
Georgia Power				
Assets:				
Energy-related derivatives	$ —	$ 3	$ —	$ 3
Interest rate derivatives	—	5	—	5
Nuclear decommissioning trusts[b] [c]				
Domestic equity	182	1	—	183
Foreign equity	—	125	—	125
U.S. Treasury and government agency securities	—	95	—	95
Municipal bonds	—	78	—	78
Corporate bonds	—	169	—	169
Mortgage and asset backed securities	—	108	—	108
Other	53	3	—	56
Total	$ 235	$ 587	$ —	$ 822
Liabilities:				
Energy-related derivatives	$ —	$ 17	$ —	$ 17
Interest rate derivatives	—	4	—	4
Total	$ —	$ 21	$ —	$ 21
Gulf Power				
Assets:				
Cash equivalents	$ 18	$ —	$ —	$ 18
Liabilities:				
Energy-related derivatives	—	74	—	74
Mississippi Power				
Assets:				
Cash equivalents	$ 182	$ —	$ —	$ 182
Liabilities:				
Energy-related derivatives	—	41	—	41
Southern Power				
Assets:				
Cash equivalents	$ 206	$ —	$ —	$ 206

(a) For additional detail, see the nuclear decommissioning trusts sections for Alabama Power and Georgia Power in this table.

(b) Excludes receivables related to investment income, pending investment sales, payables related to pending investment purchases, and currencies.

(c) Includes the investment securities pledged to creditors and collateral received and excludes payables related to the securities lending program. As of June 30, 2015, approximately $39 million of the fair market value of Georgia Power's nuclear decommissioning trust funds' securities were on loan to creditors under the funds' managers' securities lending program.

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 financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally, implied volatility of interest rate options. See Note (H) herein for additional information on how these derivatives are used.

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' judgment, are also obtained when available.

Investments in private equity and real estate within Alabama Power's nuclear decommissioning trusts are generally classified as Level 3, as the underlying assets typically do not have observable inputs. The fund manager values these assets using various inputs and techniques depending on the nature of the underlying investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

"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 June 30, 2015, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

As of June 30, 2015:	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
	(in millions)			
Southern Company				
Nuclear decommissioning trusts:				
Foreign equity funds	$ 125	None	Monthly	5 days
Equity - commingled funds	50	None	Daily	Daily
Debt - commingled funds	16	None	Daily	5 days
Other - commingled funds	3	None	Daily	Not applicable
Other - money market funds	53	None	Daily	Not applicable
Trust-owned life insurance	117	None	Daily	15 days
Cash equivalents:				
Money market funds	533	None	Daily	Not applicable
Alabama Power				
Nuclear decommissioning trusts:				
Equity - commingled funds	$ 50	None	Daily	Daily
Debt - commingled funds	16	None	Daily	5 days
Trust-owned life insurance	117	None	Daily	15 days
Cash equivalents:				
Money market funds	81	None	Daily	Not applicable
Georgia Power				
Nuclear decommissioning trusts:				
Foreign equity funds	$ 125	None	Monthly	5 days
Other - commingled funds	3	None	Daily	Not applicable
Other - money market funds	53	None	Daily	Not applicable
Gulf Power				
Cash equivalents:				
Money market funds	$ 18	None	Daily	Not applicable
Mississippi Power				
Cash equivalents:				
Money market funds	$ 182	None	Daily	Not applicable
Southern Power				
Cash equivalents:				
Money market funds	$ 206	None	Daily	Not applicable

The NRC requires licensees of commissioned 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 (the Funds) to comply with the NRC's regulations. The foreign equity fund in Georgia Power's nuclear decommissioning trusts seeks to provide long-term capital appreciation. In pursuing this investment objective, the foreign equity fund primarily invests in a diversified portfolio of equity securities of foreign companies, including those in emerging markets. These equity securities may include, but are not limited to, common stocks, preferred stocks, real estate investment trusts, convertible securities, depositary receipts (including American depositary receipts, European depositary receipts, and global depositary receipts), and rights and warrants to buy common stocks. Georgia Power may withdraw all or a portion of its investment on the last business day of each month subject to a minimum withdrawal of $1 million, provided that a minimum investment of $10 million remains. If notices of withdrawal exceed 20% of the aggregate value of the foreign equity fund, then the foreign equity fund's board may refuse to

permit the withdrawal of all such investments and may scale down the amounts to be withdrawn pro rata and may further determine that any withdrawal that has been postponed will have priority on the subsequent withdrawal date.

The other-commingled funds and other-money market funds in Georgia Power's nuclear decommissioning trusts are invested primarily in a diversified portfolio of high-quality, short-term, liquid debt securities. The funds represent cash collateral received under the Funds' managers' securities lending program and/or excess cash held within each separate investment account. The primary objective of the funds is to provide a high level of current income consistent with stability of principal and liquidity. The funds invest primarily in, but not limited to, commercial paper, floating and variable rate demand notes, debt securities issued or guaranteed by the U.S. government or its agencies or instrumentalities, time deposits, repurchase agreements, municipal obligations, notes, and other high-quality short-term liquid debt securities that mature in 90 days or less. Redemptions are available on a same day basis up to the full amount of the investment in the fund. See Note 1 to the financial statements of Southern Company and Georgia Power under "Nuclear Decommissioning" in Item 8 of the Form 10-K for additional information.

Alabama Power's nuclear decommissioning trusts include investments in Trust-Owned Life Insurance (TOLI). The taxable nuclear decommissioning trusts invest in the TOLI in order to minimize the impact of taxes on the portfolios and can draw on the value of the TOLI through death proceeds, loans against the cash surrender value, and/or the cash surrender value, subject to legal restrictions. The amounts reported in the table above reflect the fair value of investments the insurer has made in relation to the TOLI agreements. The nuclear decommissioning trusts do not own the underlying investments, but the fair value of the investments approximates the cash surrender value of the TOLI policies. The investments made by the insurer are in commingled funds. These commingled funds, along with other equity and debt commingled funds held in Alabama Power's nuclear decommissioning trusts, primarily include investments in domestic and international equity securities and predominantly high-quality fixed income securities. These fixed income securities may include U.S. Treasury and government agency fixed income securities, non-U.S. government and agency fixed income securities, domestic and foreign corporate fixed income securities, and mortgage and asset backed securities. The passively managed funds seek to replicate the performance of a related index. The actively managed funds seek to exceed the performance of a related index through security analysis and selection. See Note 1 to the financial statements of Southern Company and Alabama Power under "Nuclear Decommissioning" in Item 8 of the Form 10-K for additional information.

Southern Company, Alabama Power, and Georgia Power continue to elect the option to fair value investment securities held in the nuclear decommissioning trust funds. For the three and six months ended June 30, 2015, the change in fair value of the funds, including reinvested interest and dividends reduced by the funds' expenses, increased by $44 million and $109 million, respectively, at Southern Company. For the three and six months ended June 30, 2015, Alabama Power recorded an increase in fair value of $50 million and $97 million, respectively, as an increase in regulatory liabilities. For the three and six months ended June 30, 2015, Georgia Power recorded a decrease in fair value of $6 million and an increase of $12 million, respectively, as a reduction of its regulatory asset related to its ARO.

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the investment in the money market funds.

As of June 30, 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:		
Southern Company	$ 26,156	$ 26,973
Alabama Power	$ 7,295	$ 7,621
Georgia Power	$ 10,379	$ 10,767
Gulf Power	$ 1,370	$ 1,438
Mississippi Power	$ 2,275	$ 2,246
Southern Power	$ 2,262	$ 2,302

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 registrants.

(D) STOCKHOLDERS' EQUITY

Earnings per Share

For Southern Company, the only difference in computing basic and diluted earnings per share is attributable to awards outstanding under the stock option and performance share plans. See Note 8 to the financial statements of Southern Company in Item 8 of the Form 10-K for information on the stock option and performance share plans. The effect of both stock options and performance share award units was determined using the treasury stock method. Shares used to compute diluted earnings per share were as follows:

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	**Six Months Ended June 30, 2015**	Six Months Ended June 30, 2014
		(in millions)		
As reported shares	**909**	895	**910**	892
Effect of options and performance share award units	**3**	4	**4**	4
Diluted shares	**912**	899	**914**	896

Stock options and performance share award units that were not included in the diluted earnings per share calculation because they were anti-dilutive were 15 million and 1 million for the three and six months ended June 30, 2015, respectively, and were 8 million and 17 million for the three and six months ended June 30, 2014, respectively.

Changes in Stockholders' Equity

The following table presents year-to-date changes in stockholders' equity of Southern Company:

	Number of Common Shares					
	Issued	Treasury	Common Stockholders' Equity	Preferred and Preference Stock of Subsidiaries	Noncontrolling Interest(*)	Total Stockholders' Equity
	(in thousands)			*(in millions)*		
Balance at December 31, 2014	908,502	(725)	$ 19,949	$ 756	$ 221	$ 20,926
Net income after dividends on preferred and preference stock	—	—	1,138	—	—	1,138
Other comprehensive income (loss)	—	—	7	—	—	7
Stock issued	3,222	—	117	—	—	117
Stock-based compensation	—	—	66	—	—	66
Stock repurchased, at cost	—	(2,599)	(115)	—	—	(115)
Cash dividends on common stock	—	—	(972)	—	—	(972)
Preference stock redemption	—	—	—	(150)	—	(150)
Contributions from noncontrolling interest	—	—	—	—	135	135
Distributions to noncontrolling interest	—	—	—	—	(5)	(5)
Net income attributable to noncontrolling interest	—	—	—	—	4	4
Other	—	25	(8)	3	—	(5)
Balance at June 30, 2015	**911,724**	**(3,299)**	**$ 20,182**	**$ 609**	**$ 355**	**$ 21,146**
Balance at December 31, 2013	892,733	(5,647)	$ 19,008	$ 756	$ —	$ 19,764
Net income after dividends on preferred and preference stock	—	—	962	—	—	962
Other comprehensive income (loss)	—	—	4	—	—	4
Treasury stock re-issued	—	4,739	216	—	—	216
Stock issued	3,898	—	161	—	—	161
Stock repurchased, at cost	—	—	(5)	—	—	(5)
Cash dividends on common stock	—	—	(920)	—	—	(920)
Other	—	(27)	—	—	—	—
Balance at June 30, 2014	896,631	(935)	$ 19,426	$ 756	$ —	$ 20,182

(*) Primarily related to Southern Power Company.

Stock Repurchased

On March 2, 2015, Southern Company announced a program to repurchase up to 20 million shares of Southern Company common stock to offset all or a portion of the incremental shares issued under its employee and director equity compensation plans, including through stock option exercises, until December 31, 2017. Under this program, approximately 2.6 million shares have been repurchased through June 30, 2015 at a total cost of approximately $115 million. Pursuant to board approval, Southern Company may repurchase shares through open market

purchases or privately negotiated transactions, including accelerated or other share repurchase programs, in accordance with applicable securities laws.

(E) FINANCING

Bank Credit Arrangements

Bank credit arrangements provide liquidity support to the registrants' commercial paper borrowings and the traditional operating companies' variable rate pollution control revenue bonds. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of June 30, 2015 was approximately $1.9 billion (comprised of approximately $810 million at Alabama Power, $970 million at Georgia Power, $69 million at Gulf Power, and $40 million at Mississippi Power). In addition, at June 30, 2015, the traditional operating companies had approximately $368 million (comprised of approximately $200 million at Alabama Power, $122 million at Georgia Power, and $46 million at Gulf Power) of fixed rate pollution control revenue bonds outstanding that were required to be reoffered within the next 12 months. See Note 6 to the financial statements of each registrant under "Bank Credit Arrangements" in Item 8 of the Form 10-K for additional information. See "Financing Activities" herein for additional information.

The following table outlines the committed credit arrangements by company as of June 30, 2015:

	Expires						Executable Term Loans		Due Within One Year	
Company	2015	2016	2017	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
	(in millions)				*(in millions)*		*(in millions)*		*(in millions)*	
Southern Company	$ —	$ —	$ —	$ 1,000	$ 1,000	$ 1,000	$ —	$ —	$ —	$ —
Alabama Power	154	124	—	1,030	1,308	1,307	58	—	58	170
Georgia Power	—	150	—	1,600	1,750	1,737	—	—	—	150
Gulf Power	20	225	30	—	275	275	50	—	50	195
Mississippi Power	40	255	—	—	295	265	30	40	70	225
Southern Power	—	—	—	500	500	466	—	—	—	—
Other	25	45	—	—	70	70	20	—	20	50
Total	$ 239	$ 799	$ 30	$ 4,130	$ 5,198	$ 5,120	$ 158	$ 40	$ 198	$ 790

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.

Financing Activities

The following table outlines the long-term debt financing activities for Southern Company and its subsidiaries for the first six months of 2015:

Company[a]	Senior Note Issuances	Senior Note Redemptions	Revenue Bond Issuances and Reofferings of Purchased Bonds[b]	Revenue Bond Maturities and Repurchases	Other Long-Term Debt Issuances	Other Long-Term Debt Redemptions and Maturities[c]
			(in millions)			
Southern Company	$ 600	$ —	$ —	$ —	$ —	$ —
Alabama Power	975	250	80	134	—	—
Georgia Power	—	125	170	65	600	5
Mississippi Power	—	—	—	—	—	351
Southern Power	650	—	—	—	—	—
Other	—	—	—	—	—	9
Total	$ 2,225	$ 375	$ 250	$ 199	$ 600	$ 365

(a) Gulf Power did not issue or redeem any long-term debt during the first six months of 2015.

(b) Includes reoffering by Alabama Power of $80 million aggregate principal amount of revenue bonds previously purchased and held by Alabama Power since April 2015 and reofferings by Georgia Power of $104.6 million and $65 million aggregate principal amount of revenue bonds previously purchased and held by Georgia Power since 2013 and April 2015, respectively.

(c) Includes reductions in capital lease obligations resulting from cash payments under capital leases.

Southern Company

In June 2015, Southern Company issued $600 million aggregate principal amount of Series 2015A 2.750% Senior Notes due June 15, 2020. The proceeds were used to pay a portion of Southern Company's outstanding short-term indebtedness and for other general corporate purposes.

Alabama Power

In March 2015, Alabama Power issued $550 million aggregate principal amount of Series 2015A 3.750% Senior Notes due March 1, 2045. The proceeds were used to redeem $250 million aggregate principal amount of Series DD 5.65% Senior Notes due March 15, 2035 and for general corporate purposes, including Alabama Power's continuous construction program.

In April 2015, Alabama Power purchased and held $80 million aggregate principal amount of Industrial Development Board of the City of Mobile, Alabama Pollution Control Revenue Bonds (Alabama Power Company Barry Plant Project), Series 2007-B. Alabama Power reoffered these bonds to the public in May 2015.

Also in April 2015, Alabama Power issued $175 million additional aggregate principal amount of its Series 2015A 3.750% Senior Notes due March 1, 2045 (Additional Series 2015A Senior Notes) and $250 million aggregate principal amount of its Series 2015B 2.800% Senior Notes due April 1, 2025 (Series 2015B Senior Notes). A portion of the proceeds of the Additional Series 2015A Senior Notes and the Series 2015B Senior Notes were used to redeem in May 2015 6.48 million shares ($162 million aggregate stated capital) of Alabama Power's 5.20% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date, 4.0 million shares ($100 million aggregate stated capital) of Alabama Power's 5.30% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date, and 6.0 million shares ($150 million aggregate stated capital) of Alabama Power's 5.625% Series Preference Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date, and the remaining net proceeds were used for general corporate purposes, including Alabama Power's continuous construction program.

Georgia Power

In April 2015, Georgia Power purchased and held $65 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Second Series 2008. Georgia Power reoffered these bonds to the public in May 2015.

In May 2015, Georgia Power reoffered to the public $104.6 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2013, which had been previously purchased and held by Georgia Power since 2013.

In June 2015, Georgia Power made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $600 million. The interest rate applicable to the $600 million principal amount is 3.283% for an interest period that extends 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. Georgia Power settled $350 million of interest rate swaps related to this borrowing for approximately $6 million, which will be amortized to interest expense over 10 years.

Mississippi Power

In April 2015, Mississippi Power entered into two floating rate bank loans with a maturity date of April 1, 2016, in an aggregate principal amount of $475 million, bearing interest based on one-month LIBOR. The proceeds of these loans were used for the repayment of term loans in an aggregate principal amount of $275 million, working capital, and other general corporate purposes, including Mississippi Power's ongoing construction program. Mississippi Power also amended three outstanding floating rate bank loans for an aggregate principal amount of $425 million, which, among other things, extended the maturity dates from various dates in 2015 to April 1, 2016.

In June 2015, Mississippi Power issued an 18-month floating rate promissory note to Southern Company bearing interest based on one-month LIBOR. This note was for an aggregate principal amount of approximately $301 million, the amount paid by Southern Company to SMEPA pursuant to Southern Company's guarantee of the return of SMEPA's deposit in connection with the termination of the APA. See Note (B) under "Integrated Coal Gasification Combined Cycle – Termination of Proposed Sale of Undivided Interest to SMEPA" herein for additional information.

Southern Power

In May 2015, Southern Power Company issued $350 million aggregate principal amount of Series 2015A 1.500% Senior Notes due June 1, 2018 and $300 million aggregate principal amount of Series 2015B 2.375% Senior Notes due June 1, 2020. The proceeds were used to repay a portion of its outstanding short-term indebtedness, for other general corporate purposes, including Southern Power's growth strategy and continuous construction program, and for a portion of the subsequent repayment at maturity of $525 million aggregate principal amount of Southern Power Company's 4.875% Senior Notes on July 15, 2015.

(F) RETIREMENT BENEFITS

Southern Company has a defined benefit, trusteed, pension plan covering substantially all employees. The qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. 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 operating companies fund related other postretirement trusts to the extent required by their respective regulatory commissions.

See Note 2 to the financial statements of Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power in Item 8 of the Form 10-K for additional information.

Components of the net periodic benefit costs for the three and six months ended June 30, 2015 and 2014 were as follows:

Pension Plans	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power
			(in millions)		
Three Months Ended June 30, 2015					
Service cost	$ 64	$ 15	$ 18	$ 3	$ 3
Interest cost	111	27	39	5	6
Expected return on plan assets	(181)	(44)	(63)	(8)	(9)
Amortization:					
Prior service costs	7	1	2	—	1
Net (gain)/loss	54	13	19	2	2
Net cost	$ 55	$ 12	$ 15	$ 2	$ 3
Six Months Ended June 30, 2015					
Service cost	$ 128	$ 30	$ 36	$ 6	$ 6
Interest cost	222	53	77	10	11
Expected return on plan assets	(362)	(89)	(126)	(16)	(17)
Amortization:					
Prior service costs	13	3	5	—	1
Net (gain)/loss	108	27	38	5	5
Net cost	$ 109	$ 24	$ 30	$ 5	$ 6
Three Months Ended June 30, 2014					
Service cost	$ 54	$ 12	$ 15	$ 1	$ 2
Interest cost	108	26	38	5	5
Expected return on plan assets	(162)	(42)	(56)	(7)	(7)
Amortization:					
Prior service costs	7	2	2	1	1
Net (gain)/loss	27	8	10	1	1
Net cost	$ 34	$ 6	$ 9	$ 1	$ 2
Six Months Ended June 30, 2014					
Service cost	$ 107	$ 24	$ 31	$ 4	$ 5
Interest cost	217	52	76	10	10
Expected return on plan assets	(323)	(84)	(113)	(14)	(14)
Amortization:					
Prior service costs	13	3	5	1	1
Net (gain)/loss	55	16	20	2	2
Net cost	$ 69	$ 11	$ 19	$ 3	$ 4

Postretirement Benefits	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power
			(in millions)		
Three Months Ended June 30, 2015					
Service cost	$ 5	$ 2	$ 1	$ —	$ 1
Interest cost	20	5	9	1	1
Expected return on plan assets	(14)	(7)	(6)	(1)	(1)
Amortization:					
Prior service costs	1	—	—	—	—
Net (gain)/loss	4	1	3	—	—
Net cost	$ 16	$ 1	$ 7	$ —	$ 1
Six Months Ended June 30, 2015					
Service cost	$ 11	$ 3	$ 3	$ —	$ 1
Interest cost	39	10	17	2	2
Expected return on plan assets	(29)	(13)	(12)	(1)	(1)
Amortization:					
Prior service costs	2	1	—	—	—
Net (gain)/loss	9	1	6	—	—
Net cost	$ 32	$ 2	$ 14	$ 1	$ 2
Three Months Ended June 30, 2014					
Service cost	$ 6	$ 2	$ 1	$ 1	$ 1
Interest cost	20	5	9	1	1
Expected return on plan assets	(15)	(7)	(7)	(1)	(1)
Amortization:					
Prior service costs	1	1	—	—	—
Net (gain)/loss	—	—	1	—	—
Net cost	$ 12	$ 1	$ 4	$ 1	$ 1
Six Months Ended June 30, 2014					
Service cost	$ 11	$ 3	$ 3	$ 1	$ 1
Interest cost	40	10	17	2	2
Expected return on plan assets	(30)	(13)	(13)	(1)	(1)
Amortization:					
Prior service costs	2	2	—	—	—
Net (gain)/loss	1	—	1	—	—
Net cost	$ 24	$ 2	$ 8	$ 2	$ 2

(G) INCOME TAXES

Current and Deferred Income Taxes

State of Georgia Tax Benefits

During the second quarter 2015, an agreement was reached with the Georgia Department of Revenue that will allow Southern Company to utilize a net operating loss carryforward over a four-year period beginning in 2017. Consequently, Southern Company reversed the related valuation allowance and recognized approximately $24 million in net tax benefits as of June 30, 2015. See Note 5 to the financial statements of Southern Company under "Current and Deferred Income Taxes" in Item 8 of the Form 10-K for additional information.

Southern Power ITC Carryforwards

Southern Power had federal ITC carryforwards which are expected to result in $428 million of federal income tax benefits as of June 30, 2015, compared to $305 million as of December 31, 2014. The carryforwards as of June 30, 2015 expire between 2031 and 2035 and are expected to be utilized by the end of 2016.

Effective Tax Rate

See Note 5 to the financial statements of each registrant in Item 8 of the Form 10-K for additional tax information.

Mississippi Power

Mississippi Power's effective tax rate was 19.0% for the six months ended June 30, 2015 compared to (51.1)% for the corresponding period in 2014. The increase was primarily due to higher net income, partially offset by a decrease in non-taxable AFUDC equity related to the construction of the Kemper IGCC.

Southern Power

Southern Power's effective tax rate was 13.7% for the six months ended June 30, 2015 compared to 0.3% for the corresponding period in 2014. The increase was primarily due to beneficial changes that impacted 2014 state income taxes, which were partially offset by increased federal income tax benefits related to ITCs in the current year.

Unrecognized Tax Benefits

See Note 5 to the financial statements of Southern Company under "Unrecognized Tax Benefits" in Item 8 of the Form 10-K for additional information.

Changes during 2015 for unrecognized tax benefits were as follows:

	Mississippi Power	Southern Power	Southern Company
		(in millions)	
Unrecognized tax benefits as of December 31, 2014	$ 165	$ 5	$ 170
Tax positions from current periods	—	2	2
Tax positions from prior periods	230	—	231
Reductions due to settlements	(5)	—	(5)
Balance as of June 30, 2015	$ 390	$ 7	$ 398

The tax positions from prior periods relate primarily to 2008 through 2013 amended federal income tax returns that were filed to include deductions for Kemper IGCC-related R&E expenditures. See "Section 174 Research and Experimental Deduction" herein for additional information.

The impact on the effective tax rate, if recognized, was as follows:

	As of June 30, 2015			As of December 31, 2014
	Mississippi Power	Southern Power	Southern Company	Southern Company
		(in millions)		
Tax positions impacting the effective tax rate	$ —	$ 7	$ 8	$ 10
Tax positions not impacting the effective tax rate	390	—	390	160
Balance of unrecognized tax benefits	$ 390	$ 7	$ 398	$ 170

The tax positions impacting the effective tax rate primarily relate to federal income tax benefits related to ITCs. The tax positions not impacting the effective tax rate relate to deductions for Kemper IGCC-related R&E expenditures. See "Section 174 Research and Experimental Deduction" herein for additional information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Section 174 Research and Experimental Deduction

Southern Company reduced tax payments for 2014, and included in its 2013 consolidated federal income tax return deductions for R&E expenditures related to the Kemper IGCC. In May 2015, Southern Company amended its 2008 through 2013 federal income tax returns to include deductions for Kemper IGCC-related R&E expenditures.

The Kemper IGCC is based on first-of-a-kind technology, and Mississippi Power and Southern Company believe that a significant portion of the plant costs qualify as deductible R&E expenditures under Internal Revenue Code Section 174. The IRS is currently reviewing the underlying support for the deduction, but has not completed its audit of these expenditures. Due to the uncertainty related to this tax position, Mississippi Power and Southern Company had related unrecognized tax benefits associated with these R&E deductions of approximately $390 million and associated interest of $5 million as of June 30, 2015.

The ultimate outcome of this matter cannot be determined at this time.

(H) DERIVATIVES

Southern Company, the traditional operating companies, and Southern Power are exposed to market risks, primarily commodity price risk and interest 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 gross basis. See Note (C) herein 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 traditional operating companies and Southern Power enter 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 traditional operating companies have limited exposure to market volatility in commodity fuel prices and prices of electricity. Each of the traditional operating companies manages fuel-hedging programs, implemented per the guidelines of their respective state PSCs, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. The traditional operating companies (with respect to wholesale generating capacity) and Southern Power have limited exposure to market volatility in commodity fuel

prices and prices of electricity because their long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, the traditional operating companies and Southern Power may be exposed to market volatility in energy-related commodity prices to the extent any uncontracted wholesale generating capacity is used to sell electricity.

To mitigate residual risks relative to movements in electricity prices, the traditional operating companies and Southern Power may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the traditional operating companies and Southern Power may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

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 operating companies' 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 and 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 June 30, 2015, the net volume of energy-related derivative contracts for natural gas positions for the Southern Company system, together with the longest hedge date over which the respective entity is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest non-hedge date for derivatives not designated as hedges, were as follows:

	Net Purchased mmBtu	Longest Hedge Date	Longest Non-Hedge Date
	(in millions)		
Southern Company	220	2020	2017
Alabama Power	49	2018	—
Georgia Power	47	2017	—
Gulf Power	80	2020	—
Mississippi Power	43	2018	—
Southern Power	1	2015	2017

In addition to the volumes discussed in the above table, the traditional 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 5 million mmBtu for Southern Company, 1 million mmBtu for Alabama Power, 3 million mmBtu for Georgia Power, and 1 million mmBtu for Southern Power.

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to earnings for the next 12-month period ending June 30, 2016 are immaterial for all registrants.

Interest Rate Derivatives

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

At June 30, 2015, the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) at June 30, 2015
	(in millions)				*(in millions)*
Cash Flow Hedges of Forecasted Debt					
Alabama Power	$ 200	3-month LIBOR	2.93%	October 2025	$ (7)
Georgia Power	350	3-month LIBOR	2.57%	November 2025	(1)
Cash Flow Hedges of Existing Debt					
Georgia Power	250	3-month LIBOR + 0.32%	0.75%	March 2016	—
Georgia Power	200	3-month LIBOR + 0.40%	1.01%	August 2016	—
Fair Value Hedges on Existing Debt					
Southern Company	250	1.30%	3-month LIBOR + 0.17%	August 2017	2
Southern Company	300	2.75%	3-month LIBOR + 0.92%	June 2020	1
Georgia Power	250	5.40%	3-month LIBOR + 4.02%	June 2018	1
Georgia Power	200	4.25%	3-month LIBOR + 2.46%	December 2019	1
Total	$ 2,000				$ (3)

The estimated pre-tax gains (losses) that will be reclassified from accumulated OCI to interest expense for the next 12-month period ending June 30, 2016 are immaterial for all registrants. Southern Company and certain subsidiaries have deferred gains and losses that are expected to be amortized into earnings through 2037.

Derivative Financial Statement Presentation and Amounts

At June 30, 2015, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

Asset Derivatives at June 30, 2015

Derivative Category and Balance Sheet Location	Fair Value					
	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
			(in millions)			
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:						
Other current assets	$ 5	$ 2	$ 3	$ —	$ —	N/A
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:						
Other current assets	$ 11	$ —	$ 5	$ —	$ —	$ —
Total asset derivatives	$ 16	$ 2	$ 8	$ —	$ —	$ —

Liability Derivatives at June 30, 2015

Derivative Category and Balance Sheet Location	Fair Value					
	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
			(in millions)			
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:						
Other current liabilities(*)	$ 99	$ 31	$ 15	$ 32	$ 21	
Other deferred credits and liabilities	81	17	2	42	20	
Total derivatives designated as hedging instruments for regulatory purposes	$ 180	$ 48	$ 17	$ 74	$ 41	N/A
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:						
Other current liabilities(*)	$ 8	$ 7	$ 1	$ —	$ —	$ —
Other deferred credits and liabilities	6	—	3	—	—	—
Total derivatives designed as hedging instruments in cash flow and fair value hedges	$ 14	$ 7	$ 4	$ —	$ —	$ —
Total liability derivatives	$ 194	$ 55	$ 21	$ 74	$ 41	$ —

(*) Gulf Power includes current liabilities related to derivatives designated as hedging instruments in "Liabilities from risk management activities."

At December 31, 2014, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

Asset Derivatives at December 31, 2014						
	Fair Value					
Derivative Category and Balance Sheet Location	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
			(in millions)			
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:						
Other current assets	$ 7	$ 1	$ 6	$ —	$ —	
Other deferred charges and assets	—	—	1	—	—	
Total derivatives designated as hedging instruments for regulatory purposes	$ 7	$ 1	$ 7	$ —	$ —	N/A
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:						
Other current assets	$ 7	$ —	$ 5	$ —	$ —	$ —
Other deferred charges and assets	1	—	1	—	—	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges	$ 8	$ —	$ 6	$ —	$ —	$ —
Derivatives not designated as hedging instruments						
Energy-related derivatives:						
Other current assets	$ 6	$ —	$ —	$ —	$ —	$ 5
Total asset derivatives	$ 21	$ 1	$ 13	$ —	$ —	$ 5

Liability Derivatives at December 31, 2014

Derivative Category and Balance Sheet Location	Fair Value					
	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
			(in millions)			
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:						
Other current liabilities(*)	$ 118	$ 32	$ 23	$ 37	$ 26	
Other deferred credits and liabilities	79	21	4	35	19	
Total derivatives designated as hedging instruments for regulatory purposes	$ 197	$ 53	$ 27	$ 72	$ 45	N/A
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:						
Other current liabilities(*)	$ 17	$ 8	$ 9	$ —	$ —	$ —
Other deferred credits and liabilities	7	—	5	—	—	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges	$ 24	$ 8	$ 14	$ —	$ —	$ —
Derivatives not designated as hedging instruments						
Energy-related derivatives:						
Other current liabilities	$ 4	$ —	$ —	$ —	$ —	$ 4
Total liability derivatives	$ 225	$ 61	$ 41	$ 72	$ 45	$ 4

(*) Gulf Power includes current liabilities related to derivatives designated as hedging instruments in "Liabilities from risk management activities."

The derivative contracts of Southern Company, the traditional operating companies, and Southern Power are not subject to master netting arrangements or similar agreements and are reported gross on each registrant's 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. Amounts related to energy-related derivative contracts and interest rate derivative contracts at June 30, 2015 and December 31, 2014 are presented in the following tables.

Derivative Contracts at June 30, 2015

	Fair Value					
	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
	(in millions)					
Assets						
Energy-related derivatives:						
Energy-related derivatives presented in the Balance Sheet [a]	$ 5	$ 2	$ 3	$ —	$ —	$ —
Gross amounts not offset in the Balance Sheet [b]	(5)	(2)	(3)	—	—	—
Net energy-related derivative assets	$ —	$ —	$ —	$ —	$ —	$ —
Interest rate derivatives:						
Interest rate derivatives presented in the Balance Sheet [a]	$ 11	$ —	$ 5	$ —	$ —	$ —
Gross amounts not offset in the Balance Sheet [b]	(8)	—	(3)	—	—	—
Net interest rate derivative assets	$ 3	$ —	$ 2	$ —	$ —	$ —
Liabilities						
Energy-related derivatives:						
Energy-related derivatives presented in the Balance Sheet [a]	$ 180	$ 48	$ 17	$ 74	$ 41	$ —
Gross amounts not offset in the Balance Sheet [b]	(5)	(2)	(3)	—	—	—
Net energy-related derivative liabilities	$ 175	$ 46	$ 14	$ 74	$ 41	$ —
Interest rate derivatives:						
Interest rate derivatives presented in the Balance Sheet [a]	$ 14	$ 7	$ 4	$ —	$ —	$ —
Gross amounts not offset in the Balance Sheet [b]	(8)	—	(3)	—	—	—
Net interest rate derivative liabilities	$ 6	$ 7	$ 1	$ —	$ —	$ —

(a) None of the registrants offsets fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.

(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

Derivative Contracts at December 31, 2014

	Fair Value					
	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
			(in millions)			
Assets						
Energy-related derivatives:						
Energy-related derivatives presented in the Balance Sheet [a]	$ 13	$ 1	$ 7	$ —	$ —	$ 5
Gross amounts not offset in the Balance Sheet [b]	(9)	—	(7)	—	—	—
Net energy-related derivative assets	$ 4	$ 1	$ —	$ —	$ —	$ 5
Interest rate derivatives:						
Interest rate derivatives presented in the Balance Sheet [a]	$ 8	$ —	$ 6	$ —	$ —	$ —
Gross amounts not offset in the Balance Sheet [b]	(8)	—	(6)	—	—	—
Net interest rate derivative assets	$ —	$ —	$ —	$ —	$ —	$ —
Liabilities						
Energy-related derivatives:						
Energy-related derivatives presented in the Balance Sheet [a]	$ 201	$ 53	$ 27	$ 72	$ 45	$ 4
Gross amounts not offset in the Balance Sheet [b]	(9)	—	(7)	—	—	—
Net energy-related derivative liabilities	$ 192	$ 53	$ 20	$ 72	$ 45	$ 4
Interest rate derivatives:						
Interest rate derivatives presented in the Balance Sheet [a]	$ 24	$ 8	$ 14	$ —	$ —	$ —
Gross amounts not offset in the Balance Sheet [b]	(8)	—	(6)	—	—	—
Net interest rate derivative liabilities	$ 16	$ 8	$ 8	$ —	$ —	$ —

(a) None of the registrants offsets fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.

(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

At June 30, 2015 and December 31, 2014, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred were as follows:

Regulatory Hedge Unrealized Gain (Loss) Recognized on the Balance Sheet at June 30, 2015

Derivative Category and Balance Sheet Location	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power
			(in millions)		
Energy-related derivatives:					
Other regulatory assets, current	$ (99)	$ (31)	$ (15)	$ (32)	$ (21)
Other regulatory assets, deferred	(81)	(17)	(2)	(42)	(20)
Other regulatory liabilities, current [a]	5	2	3	—	—
Other regulatory liabilities, deferred [b]	—	—	—	—	—
Total energy-related derivative gains (losses)	$ (175)	$ (46)	$ (14)	$ (74)	$ (41)

(a) Southern Company, Alabama Power, and Georgia Power include other regulatory liabilities, current in other current liabilities.

(b) Georgia Power includes other regulatory liabilities, deferred in other deferred credits and liabilities.

Regulatory Hedge Unrealized Gain (Loss) Recognized on the Balance Sheet at December 31, 2014

Derivative Category and Balance Sheet Location	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power
			(in millions)		
Energy-related derivatives:					
Other regulatory assets, current	$ (118)	$ (32)	$ (23)	$ (37)	$ (26)
Other regulatory assets, deferred	(79)	(21)	(4)	(35)	(19)
Other regulatory liabilities, current [a]	7	1	6	—	—
Other regulatory liabilities, deferred [b]	—	—	1	—	—
Total energy-related derivative gains (losses)	$ (190)	$ (52)	$ (20)	$ (72)	$ (45)

(a) Southern Company, Alabama Power, and Georgia Power include other regulatory liabilities, current in other current liabilities.

(b) Georgia Power includes other regulatory liabilities, deferred in other deferred credits and liabilities.

For the three months ended June 30, 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)		
			Statements of Income Location	Amount	
	2015	2014		2015	2014
	(in millions)			*(in millions)*	
Southern Company					
Interest rate derivatives	$ 31	$ —	Interest expense, net of amounts capitalized	$ (2)	$ (2)
Alabama Power					
Interest rate derivatives	$ 7	$ —	Interest expense, net of amounts capitalized	$ (1)	$ —
Georgia Power					
Interest rate derivatives	$ 24	$ —	Interest expense, net of amounts capitalized	$ (1)	$ —
Mississippi Power					
Interest rate derivatives	$ —	$ —	Interest expense, net of amounts capitalized	$ —	$ (1)
Southern Power					
Interest rate derivatives	$ —	$ —	Interest expense, net of amounts capitalized	$ —	$ (1)

For the six months ended June 30, 2015 and 2014, the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments recognized in OCI and those reclassified from accumulated OCI into earnings were immaterial for all registrants.

For the three and six months ended June 30, 2015 and 2014, the pre-tax effects of energy-related derivatives designated as cash flow hedging instruments recognized in OCI and those reclassified from accumulated OCI into earnings were immaterial for all registrants.

For the three and six months ended June 30, 2015 and 2014, the pre-tax effects of interest rate derivatives designated as fair value hedging instruments were immaterial on a gross basis for all registrants. Furthermore, the pre-tax effects of interest rate derivatives designated as fair value hedging instruments were offset by changes to the carrying value of long-term debt.

There was no material ineffectiveness recorded in earnings for any registrant for any period presented.

For the three and six months ended June 30, 2015 and 2014, the pre-tax effects of energy-related derivatives not designated as hedging instruments were immaterial for all registrants.

Contingent Features

The registrants do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain Southern Company subsidiaries. At June 30, 2015, the registrants' collateral posted with their derivative counterparties was immaterial.

At June 30, 2015, the fair value of derivative liabilities with contingent features was $49 million for all registrants. The maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $49 million and include certain agreements that could require collateral in the event that one or more Southern Company power pool participants has a credit rating change to below investment grade.

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

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

(I) ACQUISITIONS

See Note 2 to the financial statements of Southern Power under "2014 – SG2 Imperial Valley, LLC" in Item 8 of the Form 10-K for additional information. During the second quarter 2015, the fair values of the assets acquired of SG2 Imperial Valley, LLC were finalized and recorded as follows: $707 million as property, plant, and equipment and $20 million as prepayments related to transmission services.

During 2015, Southern Power Company acquired or contracted to acquire the following projects in accordance with its overall growth strategy. Acquisition-related costs were expensed as incurred and were not material.

Kay County Wind Facility

On February 24, 2015, Southern Power Company, through its wholly-owned subsidiary Southern Renewable Energy, Inc., entered into a purchase agreement with Kay Wind Holdings, LLC, a wholly-owned subsidiary of Apex

Clean Energy Holdings, LLC, the developer of the project, to acquire all of the outstanding membership interests of Kay Wind, LLC (Kay Wind) for approximately $492 million, with potential purchase price adjustments based on performance testing. Kay Wind is constructing and owns an approximately 299-MW wind facility in Kay County, Oklahoma. The wind facility is expected to begin commercial operation in late 2015, and the entire output of the facility is contracted under separate 20-year PPAs with Westar Energy, Inc. and Grand River Dam Authority. The completion of the acquisition is subject to Kay Wind achieving certain construction and project milestones, as well as various other customary conditions to closing, and is expected to close in the fourth quarter 2015. The ultimate outcome of this matter cannot be determined at this time.

Lost Hills-Blackwell Solar Facilities

On April 15, 2015, Southern Power Company, through its subsidiary Southern Renewable Partnerships, LLC (SRP), acquired 100% of the class A membership interests of Lost Hills Blackwell Holdings, LLC (Lost Hills Blackwell) from a wholly-owned subsidiary of First Solar, Inc. (First Solar), the developer of the project, for approximately $74 million. Concurrently, a wholly-owned subsidiary of First Solar acquired 100% of the class B membership interests of Lost Hills Blackwell for approximately $33 million. SRP and the class B member are entitled to 51% and 49%, respectively, of all cash distributions from Lost Hills Blackwell. In addition, Southern Power Company is entitled to substantially all of the federal tax benefits with respect to the transaction. Lost Hills Blackwell constructed and owns the approximately 22-MW Lost Hills and the approximately 13-MW Blackwell solar facilities in Kern County, California. These solar facilities began commercial operation on April 17, 2015, and their entire output is contracted under PPAs, initially to the City of Roseville, California and then to Pacific Gas and Electric Company, that together extend approximately 29 years. As of June 30, 2015, the fair values of the assets acquired were recorded as follows: $98 million as property, plant, and equipment and $9 million as a receivable related to transmission interconnection costs; however, the allocation of the purchase price to individual assets has not been finalized. The acquisition did not include any contingent consideration.

North Star Solar Facility

On April 30, 2015, Southern Power Company, through its subsidiary SRP, acquired 100% of the class A membership interests of NS Solar Holdings, LLC (North Star) from a wholly-owned subsidiary of First Solar, the developer of the project, for approximately $211 million. Concurrently, a wholly-owned subsidiary of First Solar acquired 100% of the class B membership interests of North Star for approximately $100 million. SRP and the class B member are entitled to 51% and 49%, respectively, of all cash distributions from North Star. In addition, Southern Power Company is entitled to substantially all of the federal tax benefits with respect to the transaction. North Star constructed and owns the approximately 61-MW North Star solar facility in Fresno County, California. The solar facility began commercial operation on June 20, 2015, and the entire output of the project is contracted under a 20-year PPA with Pacific Gas and Electric Company. As of June 30, 2015, the fair values of the assets acquired were recorded as follows: $266 million as property, plant, and equipment, $24 million as an intangible asset, and $21 million as a receivable related to transmission interconnection costs; however, the allocation of the purchase price to individual assets has not been finalized. The acquisition did not include any contingent consideration.

Construction Projects

In December 2014, Southern Power Company announced plans to build a solar photovoltaic facility, and during 2015, Southern Power Company acquired all the outstanding membership interests of five separate solar project development entities. The construction projects are in accordance with Southern Power's overall growth strategy and included in its capital program estimates for 2015. The total cost of construction incurred for these projects through June 30, 2015 was $188 million. The ultimate outcome of these matters cannot be determined at this time.

Southern Power Company's construction projects are detailed in the table below:

Solar Project	Seller	Nameplate Capacity	County Location in Georgia	Expected Commercial Operation Date	PPA Counterparty for Entire Plant Output	PPA Contract Period	Estimated Construction Cost	
		(MW)					*(in millions)*	
Taylor County	N/A	146	Taylor	Fourth quarter 2016	Cobb, Flint, and Sawnee Electric Membership Corporations	25 years	$260 - $280	
Decatur Parkway	TradeWind Energy, Inc.	84	Decatur	December 2015	Georgia Power[(a)]	25 years	$170 - $173	(b)
Decatur County	TradeWind Energy, Inc.	20	Decatur	December 2015	Georgia Power[(a)]	20 years	$ 45 - $47	(b)
Butler	CERSM, LLC and Community Energy, Inc.	103	Taylor	December 2016	Georgia Power[(a)]	30 years	$220 - $230	(b)
Pawpaw	Longview Solar, LLC	30	Taylor	December 2015	Georgia Power[(a)]	30 years	$ 70 - $80	(b)
Butler Solar Farm	Strata Solar Development, LLC	20	Taylor	December 2015	Georgia Power[(a)]	20 years	$ 42 - $48	(b)

(a) Subject to FERC approval.

(b) Includes the acquisition price of all outstanding membership interests.

(J) SEGMENT AND RELATED INFORMATION

The primary business of the Southern Company system is electricity sales by the traditional operating companies and Southern Power. The four traditional 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's reportable business segments are the sale of electricity by the four traditional operating companies and Southern Power. Revenues from sales by Southern Power to the traditional operating companies were $85 million and $199 million for the three and six months ended June 30, 2015, respectively, and $68 million and $140 million for the three and six months ended June 30, 2014, respectively. The "All Other" column includes parent Southern Company, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include 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 three and six months ended June 30, 2015 and 2014 was as follows:

	Electric Utilities						
	Traditional Operating Companies	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
			(in millions)				
Three Months Ended June 30, 2015:							
Operating revenues	$ 4,077	$ 337	$ (90)	$ 4,324	$ 43	$ (30)	$ 4,337
Segment net income (loss)[a][b]	561	46	—	607	18	4	629
Six Months Ended June 30, 2015:							
Operating revenues	$ 8,025	$ 684	$ (213)	$ 8,496	$ 83	$ (59)	$ 8,520
Segment net income (loss)[a][c]	1,038	79	—	1,117	21	—	1,138
Total assets at June 30, 2015	$ 67,362	$ 6,226	$ (277)	$ 73,311	$ 1,360	$ (490)	$ 74,181
Three Months Ended June 30, 2014:							
Operating revenues	$ 4,209	$ 329	$ (84)	$ 4,454	$ 39	$ (26)	$ 4,467
Segment net income (loss)[a]	580	31	—	611	2	(2)	611
Six Months Ended June 30, 2014:							
Operating revenues	$ 8,587	$ 680	$ (186)	$ 9,081	$ 80	$ (50)	$ 9,111
Segment net income (loss)[a][c]	899	64	—	963	2	(3)	962
Total assets at December 31, 2014	$ 64,644	$ 5,550	$ (131)	$ 70,063	$ 1,156	$ (296)	$ 70,923

(a) After dividends on preferred and preference stock of subsidiaries.

(b) Segment net income (loss) for the traditional operating companies for the three months ended June 30, 2015 includes a $23 million pre-tax charge ($14 million after tax) for estimated probable losses on the Kemper IGCC. See Note (B) under "Integrated Coal Gasification Combined Cycle – Kemper IGCC Schedule and Cost Estimate" herein for additional information.

(c) Segment net income (loss) for the traditional operating companies for the six months ended June 30, 2015 and June 30, 2014 includes a $32 million pre-tax charge ($20 million after tax) and a $380 million pre-tax charge ($235 million after tax), respectively, for estimated probable losses on the Kemper IGCC. See Note (B) under "Integrated Coal Gasification Combined Cycle – Kemper IGCC Schedule and Cost Estimate" herein for additional information.

Products and Services

Period	Electric Utilities' Revenues			
	Retail	Wholesale	Other	Total
	(in millions)			
Three Months Ended June 30, 2015	$ 3,714	$ 448	$ 162	$ 4,324
Three Months Ended June 30, 2014	3,770	515	169	4,454
Six Months Ended June 30, 2015	$ 7,256	$ 915	$ 325	$ 8,496
Six Months Ended June 30, 2014	7,628	1,119	334	9,081

PART II — OTHER INFORMATION

Item 1. Legal Proceedings.

See the Notes to the Condensed Financial Statements herein for information regarding certain legal and administrative proceedings in which the registrants are involved.

Item 1A. Risk Factors.

See RISK FACTORS in Item 1A of the Form 10-K for a discussion of the risk factors of the registrants. There have been no material changes to these risk factors from those previously disclosed in the Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

(c) Issuer Purchases of Equity Securities

2015	Total Number of Shares Purchased (*)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (*)	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs (*)
April 1 – April 30	—	N/A	N/A	N/A
May 1 – May 31	—	N/A	N/A	N/A
June 1 – June 30	—	N/A	N/A	N/A
Total	**—**	**N/A**	**N/A**	**17,400,634**

(*) On March 2, 2015, Southern Company announced a program to repurchase up to 20 million shares of Southern Company common stock to offset all or a portion of the incremental shares issued under its employee and director equity compensation plans, including through stock option exercises, until December 31, 2017. There were no repurchases under this program in the second quarter 2015. As of June 30, 2015, Southern Company had repurchased a total of 2,599,366 shares under this program.

Item 6. Exhibits.

The exhibits below with an asterisk (*) preceding the exhibit number are filed herewith. The remaining exhibits have previously been filed with the SEC and are incorporated herein by reference. The exhibits marked with a pound sign (#) are management contracts or compensatory plans or arrangements.

(3) Articles of Incorporation and By-Laws

(a)1 - By-laws of Southern Company as amended effective May 27, 2015, and as presently in effect. (Designated in Form 8-K dated May 27, 2015, File No. 1-3526, as Exhibit 3.1.)

(4) Instruments Describing Rights of Security Holders, Including Indentures

Southern Company

(a)1 - Eleventh Supplemental Indenture to Senior Note Indenture dated as of June 12, 2015, providing for the issuance of the Series 2015A 2.750% Senior Notes due June 15, 2020. (Designated in Form 8-K dated June 9, 2015, File No. 1-3526, as Exhibit 4.2.)

Southern Power

(f)1 - Sixth Supplemental Indenture to Senior Note Indenture dated as of May 20, 2015, providing for the issuance of the Series 2015A 1.500% Senior Notes due June 1, 2018. (Designated in Form 8-K dated May 14, 2015, File No. 333-98553, as Exhibit 4.4(a).)

(f)2 - Seventh Supplemental Indenture to Senior Note Indenture dated as of May 20, 2015, providing for the issuance of the Series 2015B 2.375% Senior Notes due June 1, 2020. (Designated in Form 8-K dated May 14, 2015, File No. 333-98553, as Exhibit 4.4(b).)

(10) Material Contracts

Southern Company

\# (a)1 - Outside Directors Stock Plan for The Southern Company and its Subsidiaries. (Designated in Definitive Proxy Statement filed April 10, 2015, File No. 1-3526, as Appendix A.)

\# * (a)2 - First Amendment to the Deferred Compensation Plan for Outside Directors of The Southern Company, effective April 1, 2015.

Alabama Power

\# * (b)1 - First Amendment to the Deferred Compensation Plan for Outside Directors of Alabama Power Company, effective June 1, 2015.

\# (b)2 - Outside Directors Stock Plan for The Southern Company and its Subsidiaries. (Designated in Southern Company's Definitive Proxy Statement filed April 10, 2015, File No. 1-3526, as Appendix A.)

Georgia Power

* (c)1 - Amendment No. 1 to Loan Guarantee Agreement between Georgia Power and the DOE, dated as of June 4, 2015.

\# (c)2 - Outside Directors Stock Plan for The Southern Company and its Subsidiaries. (Designated in Southern Company's Definitive Proxy Statement filed April 10, 2015, File No. 1-3526, as Appendix A.)

Gulf Power

\# * (d)1 - First Amendment to the Deferred Compensation Plan for Outside Directors of Gulf Power Company, effective April 1, 2015.

(d)2 - Outside Directors Stock Plan for The Southern Company and its Subsidiaries. (Designated in Southern Company's Definitive Proxy Statement filed April 10, 2015, File No. 1-3526, as Appendix A.)

Mississippi Power

* (e)1 - First Amendment to the Deferred Compensation Plan for Outside Directors of Mississippi Power Company, effective April 1, 2015.

(e)2 - Outside Directors Stock Plan for The Southern Company and its Subsidiaries. (Designated in Southern Company's Definitive Proxy Statement filed April 10, 2015, File No. 1-3526, as Appendix A.)

(24) Power of Attorney and Resolutions

Southern Company

(a)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2014, File No. 1-3526 as Exhibit 24(a).)

Alabama Power

(b)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2014, File No. 1-3164 as Exhibit 24(b).)

Georgia Power

(c)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2014, File No. 1-6468 as Exhibit 24(c).)

Gulf Power

(d)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2014, File No. 001-31737 as Exhibit 24(d).)

* (d)2 - Power of Attorney for Xia Liu.

Mississippi Power

(e)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2014, File No. 001-11229 as Exhibit 24(e).)

Southern Power

(f)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2014, File No. 333-98553 as Exhibit 24(f).)

(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.

(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.

(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

[This page intentionally left blank]

THE SOUTHERN COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

THE SOUTHERN COMPANY

By *Thomas A. Fanning*
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

By *Art P. Beattie*
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: August 5, 2015

ALABAMA POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

ALABAMA POWER COMPANY

By *Mark A. Crosswhite*
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

By *Philip C. Raymond*
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: August 5, 2015

GEORGIA POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

GEORGIA POWER COMPANY

By *W. Paul Bowers*
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

By *W. Ron Hinson*
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: August 5, 2015

GULF POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

GULF POWER COMPANY

By *S. W. Connally, Jr.*
President and Chief Executive Officer
(Principal Executive Officer)

By *Xia Liu*
Vice President and Chief Financial Officer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: August 5, 2015

MISSISSIPPI POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

MISSISSIPPI POWER COMPANY

By *G. Edison Holland, Jr.*
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

By *Moses H. Feagin*
Vice President, Treasurer, and Chief Financial Officer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: August 5, 2015

SOUTHERN POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

SOUTHERN POWER COMPANY

By *Oscar C. Harper IV*
President and Chief Executive Officer
(Principal Executive Officer)

By *William C. Grantham*
Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: August 5, 2015

[This page intentionally left blank]

[This page intentionally left blank]

Certified a True Copy.

Susan D Ritenour

Secretary

GULF POWER COMPANY

Exhibit B (1)

GULF POWER COMPANY
Statement of Sources and Uses of Funds
Forecast for the Year Ended December 31, 2016
(Thousands of Dollars)

	Amount
Operating Activities:	
Depreciation	179,843
Deferred Income Taxes	8,098
Other, excluding Net Income	12,153
	200,094
Investing Activities:	
Construction Expenditures	(186,216)
Other Investing Activities	15,751
	(170,465)
Financing Activities:	
Issuance of Common Stock to or Capital Contributions by Parent Company	17,313
Pollution Control Obligations - Issued	0
Pollution Control Obligations - Retirements	0
Senior Notes - Issued	125,000
Senior Notes - Retirements	(110,000)
Interim Indebtedness	(13,757)
Dividends on Preferred Stock	(9,003)
Dividends on Common Stock	(152,975)
Other financing activities	(2,500)
	(145,922)
Total Cash Flows, excluding Net Income Before Preference Dividends	(116,293)

GULF POWER COMPANY
CONSTRUCTION BUDGET FOR GROSS PROPERTY ADDITIONS
Forecast for the Year Ended December 31, 2016
(Thousands of Dollars)

Generating Facilities	98,320
New Business Facilities	29,067
Transmission Plant Additions	15,892
Distribution Plant Additions	29,964
General Plant Additions	12,973
Total Direct Capital Expenditures	186,216
Less AFUDC-equity	0
Total Projected Gross Property Additions, excluding AFUDC-equity	186,216