SOUTHERN CO
Form 10-K
March 02, 2015

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

þ 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		Alabama Power Company
5.20% Series	5.83% Series	
5.30% Series		
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			Alabama Power Company
4.20% Series	4.60% Series	4.72% Series	
4.52% Series	4.64% Series	4.92% Series	
Preferred stock, cumulative, $100 par value			Mississippi Power Company
4.40% Series	4.60% Series		
4.72% Series			

1 As of December 31, 2014.

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 x (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 x 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 x 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 x (Response applicable to all registrants.)

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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.

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DEFINITIONS

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

Term	Meaning
Alabama Power	Alabama Power Company
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;

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- 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.

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 * (in millions)	Alabama Power	Georgia Power	Gulf Power	Mississippi Power
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		

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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 (MWs)	Alabama Power	Power South	Georgia Power	OPC	MEAG Power	Dalton	Duke Energy Florida	Southern Power	OUC	FMPA	KUA
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.

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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

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

Southern Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS."

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

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.

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

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

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 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.
/s/ 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

DEFINITIONS
(continued)

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

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Southern Company and Subsidiary Companies 2014 Annual Report
OVERVIEW
Business Activities
The Southern Company (Southern Company or the Company) is a holding company that owns all of the common stock of the 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%.

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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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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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.

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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.

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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.

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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.

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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.

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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.

CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2014, 2013, and 2012
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	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.

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CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2014, 2013, and 2012
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	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
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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
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		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
	—	—	—	—	—	1,963	—	—	—	1,963

Net income after dividends on preferred and preference stock of subsidiaries										
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.

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

The Southern Company (Southern Company or the Company) is the parent company of four traditional 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.

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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.

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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

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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

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Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning 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.

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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)

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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

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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

NOTES (continued)
Southern Company and Subsidiary Companies 2014 Annual Report

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

NOTES (continued)
Southern Company and Subsidiary Companies 2014 Annual Report

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

NOTES (continued)
Southern Company and Subsidiary Companies 2014 Annual Report

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

NOTES (continued)
Southern Company and Subsidiary Companies 2014 Annual Report

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.

NOTES (continued)
Southern Company and Subsidiary Companies 2014 Annual Report

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.

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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.

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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.

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NOTES (continued)
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As of December 31, 2013:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) (in millions)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
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 Real Estate Investments (in millions)	2014 Private Equity	2013 Real Estate Investments	2013 Private Equity
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

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NOTES (continued)
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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.

NOTES (continued)
Southern Company and Subsidiary Companies 2014 Annual Report

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 Real Estate Investments	2014 Private Equity	2013 Real Estate Investments	2013 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.

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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.

NOTES (continued)
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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.

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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.

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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.

NOTES (continued)
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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.

NOTES (continued)
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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.

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

	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.

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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.

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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

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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.

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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.

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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.

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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.

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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.

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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.

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"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

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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.

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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.

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At December 31, 2014, the following interest rate derivatives were outstanding:

	Notional Amount (in millions)	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2014 (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.

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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:

Derivative Category	Asset Derivatives Balance Sheet Location	2014	2013	Liability Derivatives 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

NOTES (continued)
Southern Company and Subsidiary Companies 2014 Annual Report

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:

Derivative Category	Unrealized Losses Balance Sheet Location	2014	2013	Unrealized Gains 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:

NOTES (continued)
Southern Company and Subsidiary Companies 2014 Annual Report

	Electric Utilities Traditional Operating Companies (in millions)	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
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 (in millions)	Wholesale	Other	Total
2014	$15,550	$2,184	$672	$18,406
2013	14,541	1,855	639	17,035
2012	14,187	1,675	616	16,478

NOTES (continued)
Southern Company and Subsidiary Companies 2014 Annual Report

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	Per Common Share Diluted Earnings	Dividends	Trading Price Range High	Trading Price Range 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.

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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.

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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.

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

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

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.
/s/ 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

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Alabama Power Company 2014 Annual Report
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.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2014 Annual Report

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.

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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.

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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.

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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.

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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

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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

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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

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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

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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.

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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.

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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.

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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.

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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	Maturity	
	Fair Value	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

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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.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2014 Annual Report

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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2014 Annual Report

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.

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.

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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 (in millions)	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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.

NOTES TO FINANCIAL STATEMENTS
Alabama Power Company 2014 Annual Report

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NOTES (continued)
Alabama Power Company 2014 Annual Report

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.

NOTES (continued)
Alabama Power Company 2014 Annual Report

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

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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.

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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

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

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

At December 31, 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.

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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.

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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

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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)

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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	

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The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 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

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Other Postretirement Benefits
Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 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)

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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

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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.
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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.

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- 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.

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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.

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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 Real Estate Investments	2014 Private Equity	2013 Real Estate Investments	2013 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.

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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:

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	2014		2013	
	Real Estate Investments (in millions)	Private Equity	Real Estate Investments	Private Equity
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.

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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%.
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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

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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

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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.

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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.

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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.

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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.

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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.

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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

NOTES (continued)
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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.

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- 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.

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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.

NOTES (continued)
Alabama Power Company 2014 Annual Report

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.

NOTES (continued)
Alabama Power Company 2014 Annual Report

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 (in millions)	Longest Hedge Date	Longest Non-Hedge Date
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.

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NOTES (continued)
Alabama Power Company 2014 Annual Report

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:

Derivative Category	Asset Derivatives Balance Sheet Location	2014	2013	Liability Derivatives 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.

NOTES (continued)
Alabama Power Company 2014 Annual Report

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:

Derivative Category	Unrealized Losses Balance Sheet Location	2014	2013	Unrealized Gains 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.

NOTES (continued)
Alabama Power Company 2014 Annual Report

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

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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.

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.

/s/ W. Paul Bowers
W. Paul Bowers
Chairman, President, and Chief Executive Officer
/s/ W. Ron Hinson
W. Ron Hinson
Executive Vice President, Chief Financial Officer, and Treasurer
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.

/s/ Deloitte & Touche LLP
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

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Georgia Power Company 2014 Annual Report
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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2014 Annual Report

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.

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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.

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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.

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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.

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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.

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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

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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,

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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-

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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

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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.

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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.

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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.

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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.

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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.

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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.

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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;

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- 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.

STATEMENTS OF INCOME
For the Years Ended December 31, 2014, 2013, and 2012
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	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.

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STATEMENTS OF COMPREHENSIVE INCOME
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	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 (in millions)	2013	2012
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.

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BALANCE SHEETS
At December 31, 2014 and 2013
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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
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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
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	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
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	Number of Common Shares Issued (in millions)	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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.

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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.

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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

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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.

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Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning are based on the most current study performed in 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

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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

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

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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.

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

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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

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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.

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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.

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As of December 31, 2013:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) (in millions)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
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 Real Estate Investments (in millions)	Private Equity	2013 Real Estate Investments	Private Equity
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

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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.

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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 Real Estate Investments	Private Equity	2013 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

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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

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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.

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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	—

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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

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

	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.

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Effective Tax Rate

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

	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.

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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

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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.

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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.

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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.

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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.

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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

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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.

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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.

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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.

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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:

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	Notional Amount (in millions)	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2014 (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.

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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:

Derivative Category	Asset Derivatives Balance Sheet Location	2014	2013	Liability Derivatives 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.

NOTES (continued)
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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:

Derivative Category	Unrealized Losses Balance Sheet Location	2014	2013	Unrealized Gains 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.

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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.

SELECTED FINANCIAL AND OPERATING DATA 2010-2014
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	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)
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	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		